Response to the Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for approval by the Department of Public Utilities of amended power purchase agreements between National Grid and Cape Wind Associates, LLC., D.P.U. 10-54

Testimony and Exhibits of:

Jürgen Weiss, Ph.D.
Judy Chang

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Submitted by:

THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL

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PREFILED DIRECT TESTIMONY OF

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I. INTRODUCTION AND QUALIFICATIONS

Q. Dr. Weiss, could you please provide some background on your qualifications?

A. I am an energy economist with approximately 12 years of post-doctoral experience consulting and providing testimony on a number of issues, mostly related to energy and in particular electricity markets. I am a Principal with The Brattle Group, an international economic consulting firm headquartered in Cambridge, Massachusetts. I head the firm's climate change practice. I hold an MBA from Columbia Business School and a Ph.D. in Business Economics from Harvard University.

Q. Have you testified in state or federal regulatory proceedings or in court on issues related to this case?

A. I have testified in proceedings in state and federal court as well as before state utility commissions, including several appearances before the Vermont Public Service Board in connection with the sale of Vermont Yankee and the associated power purchasing agreement (PPA). I have also been an expert witness in federal court on issues related to the value of both U.S. and international power purchasing agreements. Finally, I have appeared as an expert in federal court on issues related to the valuation of power generation assets. I have attached my full curriculum vitae as Exhibit AG-JWJC-2.

Q. Ms. Chang, could you please also provide some background on your qualifications?

A. I am an energy economist with a policy background and 14 years experience in the power industry. In the most recent five years, my consulting practice has been focused on the economic and policy issues around renewable energy and climate change. I am also a Principal with The Brattle Group's Cambridge, Massachusetts office. I hold a Masters of Public Policy from the Harvard Kennedy School and a Bachelor of Science in Electrical Engineering from the University of California at Davis.

Q. Have you testified in state or federal regulatory proceedings or in court on issues related to this case?

A. I have testified before the Connecticut Department of Public Utility Control regarding Connecticut's Electric Distribution Companies' Integrated Resource Plans, particularly regarding issues around renewable energy market development in New England and I have submitted written testimonies in proceedings before the Federal Energy Regulatory Commission (FERC) regarding wholesale market design issues, market-based rates, and ancillary services. I have attached my curriculum vitae as Exhibit AG-JWJC-3.

Q. Why are you jointly sponsoring this testimony?

A. We are submitting this testimony jointly because our joint experience overlaps and is complementary in important aspects related to this proceeding. The Brattle Group has done a significant amount of work assessing the potential for renewable energy development in the Northeastern United States including work related to offshore wind development in the region and Judy Chang has been actively involved in that work. Dr. Weiss has also investigated the comparative costs of conventional and renewable supply resources. He has testified several times in regulatory proceedings in New England and on issues related to PPAs. Because our testimony involves interrelated issues, we decided to submit joint testimony rather than testifying separately with significant repetition.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Consistent with the Hearing Officer's ruling on the Attorney General's (AG) motion to file supplemental testimony in this proceeding, we were asked by the AG to provide an independent review and economic analysis of the Amended PPAs[1] between Nantucket Electric Company, Massachusetts Electric Company, both d/b/a National Grid (National Grid) and Cape Wind, LLC (Cape Wind) and to compare the costs of those contracts with the cost of other offshore wind projects in the U.S. and in Europe. In addition, the Attorney General's office has asked us to estimate the overall cost savings between the Amended PPAs and the original PPAs dated May 7, 2010, submitted to the Department on May 10, 2010.

III. EXECUTIVE SUMMARY

Q. Could you provide a summary of your testimony?

A. Our testimony can be summarized as follows:

1. The Amended PPAs are an improvement over the original PPAs. Compared to the initial price of $207 per megawatt hour (MWh) in the original PPAs the initial price of $187/MWh in the Amended PPAs before any adjustments (the "Base Price") reduces the PPA price by 9.7% or $20 for every MWh of output purchased under the PPAs in the initial year. Over the 15-year term of the PPAs, the reduced prices in the Amended PPAs will save ratepayers between $400 and $600 million, or between $240 million to $340 million in net present value terms.

2. In addition, the Amended PPAs include several new price and non-price provisions which may generate significant additional ratepayer benefits if actual costs — either construction or debt costs — are lower than projected in the Base Price. The

[1] First Amendment to Power Purchase Agreement (PPA 1), August 9, 2010, (Amended PPA). We will also use the terms PPA 1 and PPA 2. PPA 1 refers to the PPA under which National Grid proposed to purchase 50% of the output from Cape Wind. PPA 2 refers to the PPA National Grid intends to assign to a third party. We will use the terms PPA and PPAs whenever we refer to issues applying to both PPA 1 and PPA 2.

Amended PPAs also include an option to purchase products from Cape Wind after the 15-year PPA term at cost-based prices. We estimate the potential additional cost savings to ratepayers from these adjustments in the Amended PPAs may be several hundred million dollars. More importantly, such adjustments ensure that ratepayers will pay PPA prices that reflect any realized differences between the expected cost of the Project and its actual cost. In so doing, the Amended PPAs give ratepayers a share of any such cost savings while, at the same time, create an incentive for the developer to minimize cost and preserve price certainty at the outset of the Project.

3. Cape Wind's levelized Base Price in the Amended PPAs is \$230.4/MWh. The proposed price for the Bluewater offshore wind project is approximately equivalent to \$230.6/MWh levelized. [redacted] The pricing of the Amended PPAs, even before accounting for the benefits that ratepayers could receive from any downward adjustments resulting from lower cost of debt, lower capital cost of the project, and/or the option to extend the contract under a cost-basis term, is therefore comparable and possibly slightly lower than the costs of other offshore projects in the U.S.

4. The Base Price, by itself, is somewhat higher than the prices that would reflect the expected costs of offshore wind projects in Europe, where there is more experience with such projects. However, if some of the potential price adjustments contained in the Amended PPAs materialize, the resulting prices are more closely aligned with costs of offshore wind in Europe.

5. The Base Price in the Amended PPAs is consistent with our own estimate of Cape Wind's likely project cost.

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6. Overall, based on our analysis, the Amended PPAs compare favorably to alternative offshore wind options. Because of the added adjustments, the Amended PPAs are comparably priced to other offshore wind alternatives in the U.S. and incorporate additional desirable features that reduce the risk to ratepayers and more appropriately share potential cost savings with ratepayers than the original PPAs.

IV. THE TERMS OF THE AMENDED PPAS SHOULD BE EXPLAINED CLEARLY

Q. What is the stated price in the Amended PPAs?

A. Assuming the project qualifies for the ITC, the Base Price in the Amended PPAs is $187/MWh in 2013, increasing by 3.5% per year for 15 years.[2] This price is applicable if the project's installed capacity is 468 MW (*i.e.*, 130 turbines, each with a nameplate capacity of 3.6 MW). If the project's capacity is less than this full project size, the price increases linearly by $0.0833 per MW decrease, up to $193/MWh. The Amended PPAs also include potentially significant downward adjustments to the Base Price, which we will discuss later in our testimony.

Q. Accounting for the annual price escalation of 3.5%, and adding the remuneration to National Grid for the contracts, what would the prices be under the amended proposed PPAs?

A. Accounting for annual 3.5% price escalation (but ignoring the 4% remuneration that National Grid would receive and assuming a 468MW project size), the price starts at $187/MWh in 2013 and rises to $303/MWh in 2027. Column [a] on Table 1 below shows this price stream. When the 4% remuneration to National Grid is added, the prices that consumers pay (with ITC and at 468 MW project size) start at $194/MWh in 2013 and escalates to $315/MWh in 2027. Column [c] on Table 1 shows this price stream. If

[2] See Section 1 of Appendix X to Exhibit E of the Amended PPAs.

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Cape Wind does not receive ITC or production tax credits (PTC), the prices with and without the 4% remuneration to National Grid are shown columns [b] and [d], respectively.[3]

Table 1
Base Price under the Amended PPAs
(468 MW, with ITC, Nominal Prices)

	As Stated		Including National Grid 4% Remuneration	
Year	With ITC	Without ITC/PTC	With ITC	Without ITC/PTC
	[a]	[b]	[c]	[d]
2013	$187	$212	$194	$221
2014	$194	$220	$201	$229
2015	$200	$227	$208	$237
2016	$207	$235	$216	$245
2017	$215	$244	$223	$253
2018	$222	$252	$231	$262
2019	$230	$261	$239	$271
2020	$238	$270	$247	$281
2021	$246	$280	$256	$291
2022	$255	$289	$265	$301
2023	$264	$299	$274	$311
2024	$273	$310	$284	$322
2025	$283	$321	$294	$334
2026	$292	$332	$304	$345
2027	$303	$344	$315	$357

Q. What is the equivalent levelized price of the Base Price under the Amended PPAs?

A. At a project size of 468 MW, assuming Cape Wind receives ITC, and excluding the 4% remuneration), the levelized price of the Base Price is $230.4/MWh

[3] National Grid would receive remuneration only under the Amended PPA 1. Any remuneration of Amended PPA 2 would apply to whatever utility is assigned that contract or a portion thereof.

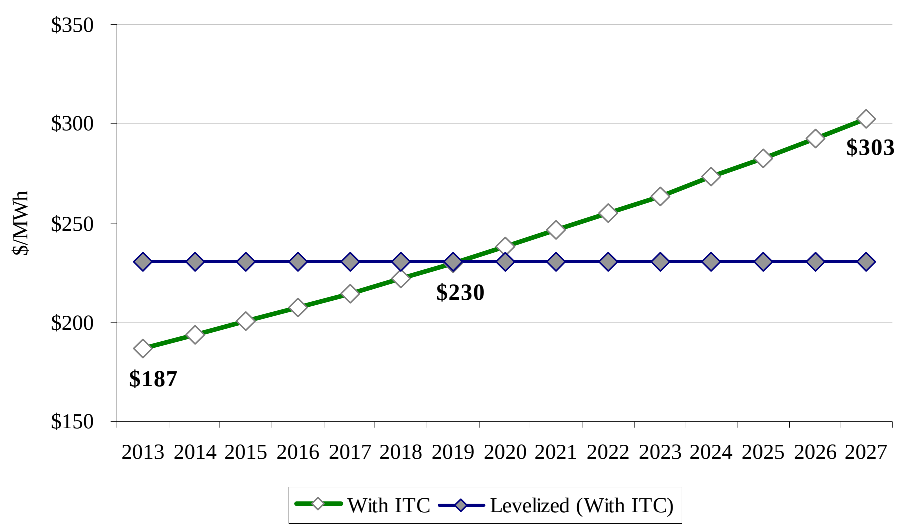
Q. What does it mean to have a levelized price of $230.4/MWh?

A. A levelized price of $230.4/MWh simply means that if ratepayers paid a constant price for every MWh of power from Cape Wind over the 15-year contract term, that price would be $230.4/MWh in each year. Because the PPAs propose a 3.5% price increase in each year of the contract, this levelized price is higher than the initial price but lower than the annual prices later in the contract. The levelized price under the PPAs is similar to paying a fixed mortgage payment over the term of a mortgage; it is the amount ratepayers would pay under the PPAs in equal payments each year for the next 15 years.

Q. Please explain how you estimated the $230.4 per MWh levelized price.

A. First, we estimated the present value (PV) of the pricing proposed in the PPAs using National Grid's 7% discount rate.[4] Then we estimated the constant nominal price which, if paid each year throughout the contract, would yield the same PV. Figure 1 shows the resulting $230.4/MWh levelized price relative to the schedule of nominal prices.

Figure 1
Proposed Nominal Prices and Levelized Price



4 Pre-filed Direct Testimony of Madison N. Milhous, Jr., ("Milhous Testimony") p. 2 and Exhibit MNM-2.

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Q. Why is it important to estimate the levelized price?

A. It is important to estimate the levelized contract price because it is important to be transparent about the actual price over the full contract term. The quoted contract price of $187/MWh leaves the impression that the price under the proposed PPAs is lower than the prices ratepayers actually will pay over the 15-year contract term. For example, as shown in Figure 1, the actual nominal price increases at a rate such that, by the final contract year 2027, ratepayers would pay $303/MWh, not the starting price of $187/MWh. This also means that the rate impact would be more significant than the rate impact for 2013.[5]

Q. Are other factors important to consider in estimating the levelized price?

A. Yes. First, the Base Price increases if the Cape Wind project size is smaller than 468 MW. The initial year price could be as high as $193 if the total project size is 396 MW or smaller.[6] An initial year price of $193 would result in a levelized price of $237.8/MWh. Also, Appendix X to Exhibit E of the Amended PPAs provides two other contract prices if the availability of investment tax credit (ITC) and production tax credit (PTC) changes. Specifically, if the ITC is not available to Cape Wind but the PTC remains available, the initial proposed price would increase to 1.10145 times the Base Price,[7] or to $206.0/MWh, assuming a 468 MW project, or a maximum of $212.6/MWh for a project smaller or equal to 396 MW. If neither the ITC nor the PTC were available to Cape Wind, the proposed price increases to 1.13526 times the Base Price,[8] or to $212.3/MWh in the initial year, assuming a 468 MW project, or a maximum of $219.1/MWh for a

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[5] See Supplemental Testimony of Jeanne A. Lloyd, Exhibit JAL-4 Supplemental, where she estimates the bill impact of the Amended PPA only for the initial year of the contract.

[6] Amended PPA, Appendix X to Exhibit E, Section 1(a)

[7] Amended PPA, Appendix X to Exhibit E, Section 2(b). This multiplier reflects the ratio of PPA prices with ITC and with PTC in the original PPA, *i.e.*, $228/MWh divided by $207/MWh.

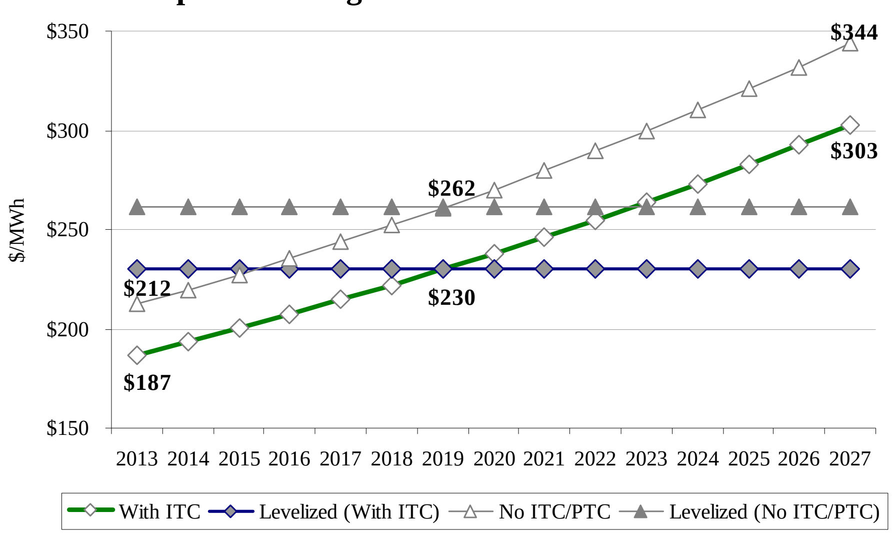
[8] Amended PPA, Appendix X to Exhibit E, Section 2(c). This multiplier reflects the ratio of original PPA prices with and without ITC/PTC, *i.e.*, $235/MWh divided by $207/MWh.

project smaller or equal to 396 MW. (The price stream for a 468 MW without ITC or PTC is shown in Table 1, column [b]) Both adjusted prices (the "Tax Credit Adjusted Price") are proposed to escalate at 3.5% per year. According to National Grid,[9] the increase in the PPA prices to account for the lack of the federal tax credits reflects an equal sharing of the resulting cost between ratepayers and the Project. So while the PPA price without the tax credits would be higher than the Base Price, ratepayers would not bear the full cost impact of lack of tax credits.

Q. What are the levelized prices associated with these two prices?

A. Since the initial proposed prices without the ITC and/or PTC are higher than the $187/MWh initial price, the corresponding levelized price (the "Tax Credit Adjusted Price") also is higher than $230.4/MWh. Figure 2 shows the nominal price path and levelized price without the ITC or PTC, again using National Grid's 7% discount rate, assuming in both cases a 468 MW project size.

Figure 2
Proposed Pricing With and Without ITC/PTC



9 Milhous Testimony, p. 19.

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Without either federal tax benefit, the proposed pricing would increase from $212.3/MWh to $343.6/MWh over the 15-year contract term. The corresponding levelized price would be $261.6/MWh. If Cape Wind qualifies for the PTC but not the ITC, the nominal and levelized prices would be between the prices shown on Figure 2. In that case, the proposed pricing would increase from $206.0/MWh to $333.4/MWh over the 15-year contract term. The corresponding levelized price would be $253.8/MWh.

Q. What is the dollar impact of adding the 4% remuneration to the proposed pricing?

A. From the perspective of ratepayers, adding the 4% remuneration to the proposed pricing increases by 4% the price ratepayers would pay in each year for PPA 1, and possibly for PPA 2 if that buyer also is eligible for remuneration. For example, as Table 1 showed, the initial price in the first contract year, assuming Cape Wind qualifies for the ITC, is not actually $187/MWh, but rather $194.5/MWh (*i.e.*, $187/MWh x 1.04). In the initial contract year, National Grid would receive $7.5 for every MWh produced and sold under PPA 1. The corresponding levelized cost to ratepayers would be $239.6/MWh. While the remuneration to National Grid increases the cost to ratepayers by $7.5 per MWh, this represents a savings relative to the original PPA pricing. At the $207/MWh initial price originally proposed in the original PPA, the remuneration would have cost ratepayers $8.3 per MWh, or almost $1/MWh more than under the Amended PPA prices.

V. THE TERMS IN THE AMENDED PPAS PROVIDE SIGNIFICANT BENEFITS TO RATEPAYERS COMPARED TO THE ORIGINAL PPAS

A. The Base Price Of The Amended PPAs Reflects Ratepayer Savings Of $587 Million Over 15 Years Relative To The Original PPAs

Q. What were the prices in the original PPAs?

A. The price in the original PPAs was $207/MWh, escalated at 3.5% per year for 15 years, assuming the project qualifies for the ITC. The equivalent levelized nominal price of those PPAs was $255/MWh. If the project does not qualify for the ITC and/or PTC, the original PPA price increases by the same proportional amounts as in the Amended PPAs.

Q. Over the 15-year life of the contract, how much will ratepayers save due to the lower Base Price of the Amended PPAs?

A. Compared to the price in the original PPAs, the Base Price in the Amended PPAs will result in a cumulative undiscounted savings (under both PPAs and assuming a 468 MW project size) of $587 million. These $587 million represent savings of approximately $341 million to ratepayers in present value terms, using the same 7% discount rate we have used to calculate levelized costs.

Q. Could the savings to ratepayers from the Base Price adjustment be lower than $587 million over the 15-year PPA term, or $341 million in NPV terms?

A. Yes they could, if the project size is reduced from 468 MW, because the Base Price in the Amended PPAs depends on the project size. Specifically, as discussed above, if the ultimate project size is less than 468 MW, the Base Price increases linearly from $187/MWh to $193/MWh for a project of 396 MW or less. Hence, if the project were to be 396 MW or less, the resulting Base Price of $193 would be $14/MWh less than the original PPA price of $207/MWh. The corresponding undiscounted decrease in payments over the 15-year duration of the PPA would be $410.9 million. The net present value of these savings to ratepayers would be approximately $239 million. These $239 million of savings would be the minimum total savings available to ratepayers since the $193/MWh is the highest base price assuming the project receives the ITC (and the original and amended PPA prices are both higher if it does not).

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Q. Why do you emphasize the fact that these savings only reflect the difference between the original price and the Base Price contained in the Amended PPAs.

A. We do so because the Amended PPAs include several important provisions that were not contained in the original PPAs. In addition to a Base Price decrease relative to the original PPAs, these other provisions in the Amended PPAs could provide significant additional cost savings to ratepayers. Importantly, by including these additional provisions, the Amended PPAs provide ratepayers some potential "up-side" if the overall cost of constructing the project turns out to be cheaper than currently anticipated by the developers. Next, we describe these benefits in more detail.

B. The Price Adjustments In The Amended PPAs Limit Developer Returns And Give Ratepayers A Share Of Potential Future Benefits

Q. What is the economic rationale for the potential price adjustments in the Amended PPAs?

A. From an economic perspective, the adjustments in the Amended PPAs serve three purposes.

First, the adjustments address the concern that any price negotiated today for an offshore wind project in the U.S. suffers from limited experience with offshore wind project development, such that the range of uncertainty around costs is larger than it would be for more mature project types. Because of these uncertainties and because PPAs set the future prices, PPAs signed under such circumstances create risk for both parties: project developers bear the risk that actual costs may be significantly greater than those projected and therefore need to include that risk premium into the price, and buyers and consumers bear the risk of overpaying if the actual costs are significantly lower than those projected. The adjustments to the PPA price if either the financing or project costs are lower than expected address this concern and provide important assurance to ratepayers against over-paying for the PPA.

Second, proposed price adjustments balance the need for relatively certain project revenues to developers and costs to ratepayers, the benefits of economies of scale, and the need to protect ratepayers from more out-of-market payments than represented by PPA 1. As we explain in more detail below, this balance is achieved through the combination of the adjustment to the Base Price up to $193/MWh based on the ultimate project size and the limit on National Grid's purchase under PPA 1.

Third, the adjustments provide ratepayers with the benefits associated with entering into a PPA to help finance one of the first offshore wind projects in the U.S. To a significant degree, the rationale for jump-starting the U.S. offshore wind industry with this particular project is the assumption that an offshore wind industry at sufficient scale will lower the cost of meeting electric and environmental demands in the long term. Since ratepayers would pay the upfront cost of getting this process underway, they also should share in this long-term benefit.

The buyers' option to extend the PPAs at cost-plus pricing after the 15-year PPA term creates such an opportunity. While we cannot be certain about the market prices (including the prices for various environmental attributes) at the end of the 15-year PPA term in 2028, if the costs of generating power from Cape Wind will be lower than the then-prevailing market prices for similar products, the ratepayers who helped pay for the construction of the project should receive these products at cost, not at the higher market prices. The Amended PPAs provide ratepayers this option.

The Amended PPA 1 also provides National Grid's ratepayers the option to amend the PPA to match the pricing and terms of any other long-term agreement into which Cape Wind or its affiliates may enter for output from the Cape Wind project or from any other project within a 50-mile radius of the Project.[10] This provision is important because it gives National Grid's ratepayers a form of price protection against the possibility that Cape Wind could offer more favorable pricing or terms to a third party after the Amended PPA 1 is executed.

C. Ratepayers Benefit from Potential Reduction in Debt Cost

Q. Please describe the first provision in the Amended PPAs that could provide an "up-side" to ratepayers

A. Referring to the first item on the "Joint Notice of Settlement" (Settlement) and the resulting Amended PPAs,[11] if the cost of debt to the developers is below 7.5% (pretax), then ratepayers realize 75% of the financing cost savings. For example, if the cost of debt turns out to be 5% instead of 7.5%, the price of the Amended PPAs would adjust downward to reflect that the actual cost of financing the project would be lower. Typically, without a price adjustment, the developers of the project would fully benefit from a lower cost of debt because after a revenue stream has been set, any reduction in costs, including the cost of financing, would directly increase the operating income of a project and likely benefit the equity holders of the project. However, the first provision of the Amended PPAs, which shares those savings with ratepayers, ensures that if the cost of debt decreases from the expected 7.5%, both equity holders and ratepayers benefit from such cost reduction, with ratepayers receiving 75% of the benefits.

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[10] First Amendment to Power Purchase Agreement, item 5.

[11] Joint Notice of Settlement, July 30, 2010, Exhibit A, item 2. Also Amended PPA, Appendix X to Exhibit E, Section 3.

Q. Aside from the potential cost benefits to ratepayers, why do you think this provision in the Settlement is a reasonable one?

A. Currently, the U.S. federal government has made available loan guarantees to developers of renewable energy. These loan guarantees are available through the Department of Energy under Title XVII of the Energy Policy Act of 2005. If Cape Wind qualifies and obtains a federal loan guarantee, it is possible that the overall cost of debt to a project like Cape Wind could be reduced significantly. Since tax payers effectively fund the loan guarantees, it is reasonable that a significant share of the benefits stemming from the loan guarantee accrues to ratepayers.

Q. What is the likely magnitude of the reduction to the cost of debt, if Cape Wind qualifies and obtains a federal loan guarantee?

A. For the portion of the debt that qualifies for the loan guarantee, it is likely that the cost of debt could drop significantly from a market rate loan. While we do not know precisely what Cape Wind's cost of debt will be, we would expect that the interest rate for a project comparable to Cape Wind would be approximately 7.5%.[12] The Amended PPAs use this assumption as the basis for determining the Base Price. With a federal loan guarantee, the weighted-average interest rate on the portion of debt under the guarantee can drop significantly, potentially to a level near or below 5%.[13] It is important to note, however, that the PPA price will be adjusted downwards whether or not this is due to receiving a federal loan guarantee as long as the actual financing costs for the Cape Wind project are lower than 7.5%.

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12 See for example World Economic Forum, "Green Investing: Toward a Clean Energy Infrastructure," REF:

13 [redacted]

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Q. If Cape Wind were able to obtain a federal loan guarantee and/or reduce its overall cost of debt to about 5.0%, what would be the resulting PPA price?

A. Using the 75:25 benefits sharing between ratepayers and Cape Wind and the 5% debt cost used in the example included in the Amended PPAs, we estimate that the resulting adjusted PPA price (the "Financing Adjusted Price") would be approximately $172.6/MWh in the first year of the PPA and would vary over the PPA term according to the financing cost savings realized in each year as the project debt is repaid. The equivalent levelized nominal price would be approximately $221.0/MWh.

Q. Could you please explain how you had arrived at the $172.6/MWh price for the first year and the levelized nominal price of $221.0/MWh?

A. Appendix X to Exhibit E of the Amended PPAs defines the adjustment for lower debt costs.[14] Based on this definition, ratepayers would receive 75% of any reductions in the after-tax financing costs. Exhibit AG-JWJC-4 shows our calculation of an example of potential savings to ratepayers of this financing cost adjustment.

We calculated the difference between the 7.5% interest rate threshold and the 5% cost of debt used in the example in the Amended PPAs. We then reduced this interest differential by the tax rate of 35% specified in the Amended PPAs. The resulting 1.6% represents the total financing cost savings on an after-tax basis. Next, we calculated the amount of debt (the "Debt Financing") to which this interest savings will be applied in each year. We used a standard 15-year loan in which the Project pays-down its debt over time by making constant principal and interest payments in each year, like a mortgage payment. As a result, the debt cost savings may vary year to year. The savings are greatest at the start of the PPA, when the debt balance is highest, and then decrease over the PPA term as the debt is paid-down. Multiplying 1.6% per year times the Debt

[14] Amended PPA, Appendix X to Exhibit E, Section 3.

Financing in each year yields the total financing cost savings in each year, 75% of which goes to ratepayers in the form of lower PPA prices in each year. Dividing the dollar amount of ratepayer savings in each year of the contract by the output of the project (in MWh) yields the financing cost adjustment on a dollars-per-MWh basis. Subtracting that amount from the Tax Credit Adjusted Price in each year yields the Financing Adjusted Price path. Based on the difference between the Tax Credit Adjusted Price and the Financing Adjusted Price in this example, we estimate the ratepayers' savings to be approximately $188 million over the 15-year PPA term, or $135 million in NPV terms, using National Grid's 7% discount rate.

Q. How likely is the PPA price to be as low as $172.6/MWh initially and $221.0/MWh levelized?

A. While we have not assessed the likelihood for Cape Wind to obtain the federal loan guarantee, the fact that Cape Wind realizes 25% of any cost savings associated with a lower cost of debt should provide Cape Wind sufficient financial incentive to pursue those savings. In addition, the total net cost of debt will only be known with certainty if/when financing for the project has been obtained and, at that point, will depend on debt market conditions, which create some additional uncertainty with respect to the net cost of debt. However, while not known with certainty, the preceding example shows this adjustment to have significant potential value to ratepayers under the Amended PPAs.

D. THE PPA PRICE MAY ALSO ADJUST DOWNWARD IF THE COST OF THE PROJECT IS LOWER THAN ANTICIPATED

Q. Could you please describe the next provision in the Settlement that might provide additional benefits to ratepayers by lowering the PPA prices?

A. The next provision in the Amended PPAs states that there would be a one-time downward price adjustment to the PPA price if the actual cost of constructing and financing the Cape Wind project turns out to be lower than currently estimated. This provision links the capital cost of the project with the cost of financing of the project.

Consider an example in which the all-in capital cost of the project is $5,600/kW. This cost would include all the cost of financing and contingencies during construction and represents the developer's anticipated upfront cost. Once the developer makes such an investment, it expects to earn a return on the project investment. The Amended PPAs establish a threshold for the developers' anticipated project return at 10.75%. If the PPA price, already adjusted for project size and financing costs, yields an internal rate of return to the Project of greater than 10.75%, the equity holders would share 60% of those benefits with the ratepayers.

Q. What is the likelihood of ratepayers realizing this additional benefit from this provision to share excess project return?

A. There is a benefit to ratepayers of simply having this cost adjustment in the Amended PPAs because it provides highly valuable insurance for ratepayers in case actual project costs end up to be significantly below current estimates. The inclusion of the provision ensures that ratepayers will not end up paying for open-ended rates of return to the Project's developer or equity investors. Rather, the provision gives the developer an incentive to minimize project costs in exchange for a 40% share of the cost savings, and it returns to the ratepayers the other 60% of such cost reductions which would have otherwise entirely gone to the Project in the form of a higher rate of return. Therefore, the mere inclusion of this provision in the Amended PPAs benefits ratepayers by aligning the price with the actual project costs.

Whether this provision also yields further benefits to ratepayers in the form of lower PPA prices depends on the realized project costs. While the developer has the incentive to maximize its return by minimizing project costs, the reduced pricing already negotiated into the Amended PPAs may make it difficult for the Project to realize a rate of return as high as the 10.75% threshold return. Based on our projection of the expected future cash flows at our Baseline cost inputs (discussed below), the Project would require significantly higher prices than the Amended PPA prices to exceed the rate of return threshold. Alternatively, the project costs would have to be significantly less than our Baseline estimate of $5,600/kW to generate such a return. For example, we estimate that at the Amended PPA prices, the realized project cost would have to fall to about $4,600/kW to generate a 10.75% return to the Project. The evidence on typical project costs suggests that outcome is relatively unlikely. This is an indication that the Amended PPAs are relatively well-priced relative to the expected costs and rates of return for such a project. Even if that were not the case, this provision assures that ratepayers would not pay the cost of excessive project returns.

E. THE PPA 2 LIMITATION PROTECTS NATIONAL GRID'S RATEPAYERS FROM OVERPAYING FOR A LARGE CONTRACT, AND IT PROVIDES CAPE WIND SOME PRICE CERTAINTY FOR THE REST OF THE PROJECT

Q. Please describe the PPA 2 Limitation Provision

A. The PPA 2 Limitation Provision contained in the Settlement clarifies that National Grid will not be purchasing the output from PPA 2. This should provide some protection to National Grid's distribution customers that they will not be bearing costs greater than those under PPA 1. In addition, this provision also provides some protection to the developers and financiers of Cape Wind that the prices and terms of PPA 1 will apply directly to PPA 2, such that if any other Massachusetts electric distribution company decides to purchase a portion of the output associated with PPA 2, those prices will mirror those of PPA 1 and Cape Wind will not be subject to another price scrutiny that might create uncertainties about the revenue stream from PPA 2.

Q. What would happen if no other entity purchases the output associated with PPA 2?

A. The PPA 2 Limitation provision limits National Grid's obligation to purchase the output under PPA 1 only as a result of this proceeding. If no other entity decides to purchase the output associated with PPA 2, Cape Wind may need to reduce the size of the project. Should that happen, National Grid may reduce its purchase under PPA 1 to the lesser of: a) the output associated with 234 MW (equivalent to 50% of the output of the current project size of 468 MW) or b) 80% of the reduced nameplate capacity.[15]

The PPA 2 Limitation provision effectively limits National Grid's purchase to the output of 234 MW and if no one decides to purchase more from Cape Wind, the project size could be reduced and National Grid's purchase may also be reduced, thus reducing the overall out-of-market payments from ratepayers. For example, if the project size decreases to 250 MW, National Grid's obligation would be reduced to purchasing 80% of 250 MW which equals 200 MW. However, if the project size decreases to 300 MW, 80% of 300 MW would remain greater than 234 MW, and therefore National Grid still would be obligated to purchase the output associated with 234 MW.

Q. If the project size decreases, wouldn't the price of PPA 1 and what is left of PPA 2 also increase and thereby *not* benefit ratepayers?

A. Yes the price would increase, but only to a level that we think still keeps the PPA price at a level comparable with other potential offshore wind projects. Based on the Capacity size adjustment provision, the price of PPA 1 and PPA 2 could increase up to \$193/MWh. Thus, in the example above, if the project size were to be reduced to 250 MW or 300 MW, the price after adjusting for the project size still would be \$193/MWh, not an even higher price. While this price increase may appear to be undesirable to ratepayers, the resulting \$193/MWh price is still significantly lower than the price

[15] Amended PPA, Section 4.10(ii).

proposed in the original PPA. It is possible that project costs, including materials, construction, operation, and maintenance could be greater for Cape Wind if the project size were smaller since there could well be some effects related to economies of scale, particularly for construction costs and operation and maintenance costs.

Q. Do you know for sure that the costs of construction and operations and maintenance would increase with smaller project?

A. Actual data on Cape Wind's construction costs and O&M costs will not be available until the Project is built and operating, respectively. However, given that some elements of the costs of both construction and subsequent operations and maintenance are fixed, it is reasonable to assume that in general there is the potential for economies (and diseconomies) of scale. Such scale economies are frequently discussed in the literature on offshore wind development.[16]

F. THE OPTION TO EXTEND THE PPAS AT COST-PLUS PRICING PROVIDES RATEPAYERS AN OPTION TO BENEFIT AFTER THE CONTRACT TERM

Q. Please describe the "Extension Price" option in the Amended PPAs.

A. Section 5 of Appendix X to Exhibit E of the Amended PPAs describes the price to be paid ("Extension Price") if National Grid and/or the buyer of PPA 2 exercises the option to purchase products from the Cape Wind project after the expiration of the original 15-year PPA term. In general, the Extension Price allows for recovery of ongoing operating expenses and a return on any undepreciated portion of the project's book assets.

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[16] See for example New York's Offshore Wind Energy Development Potential in the Great Lakes, A Feasibility Study, NYSERDA, April 2010, p.16.

Q. Have you estimated the magnitude of potential savings associated with the option to purchase output from the project for an additional 10 years under the conditions of the Amended PPAs?

A. We have, but it is important to caveat any such estimate with significant uncertainties. Since neither the Extension Price nor the market price after the end of the term of the PPAs are known, any such savings estimated by calculating the difference between two highly uncertain cost and price streams will be highly uncertain. The uncertainty is even further increased by the fact that the post-PPA pricing under the option to extend purchases for an additional 10 years asks for an independent expert to estimate the cost of capital that would allow a reasonable return on the remaining book assets of the project going forward. Because of all these complexities, we have estimated the potential value of the option to extend the PPAs for an additional 10 years in a very simple form, namely by comparing the estimated project costs in years 16 through 25 (given a range of assumptions we also use for our own estimate of Cape Wind's project cost described in detail below) relative to market price forecasts at which power and related products would be available during the same time frame.

Q. What is your estimate of the potential value of a PPA extension under a cost-based price?

A. Using the ESAI price forecast provided by National Grid, market revenues for a similar product in years 16 through 25 would come from the sale of energy, capacity, and RECs. We used the energy prices as forecast by ESAI.[17] [redacted] Assuming conservatively that a market value of a

[17] Milhous Exhibit MNM-3 Price Forecast for Capacity Energy and RECs (ESAI).

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similar product would only receive 26% of capacity credit[18] [redacted] we estimate that the market price for a similar product would be between about $138/MWh [redacted] and $163 [redacted] in the first year after the end of the initial PPA term.

To calculate the expected benefit of this reduced pricing, we then estimated the potential cost-based price during the extension period. The most relevant project costs to be evaluated are the cost of O&M and the amount of book assets that have not yet been depreciated.[19] If the project were depreciated over 20 years on a book basis, 25% of its initial cost would remain undepreciated after the first 15 years (*i.e.*, five more years of depreciation would remain at the end of the contract term),[20] and we estimate that a reasonable cost-based price would be approximately $163/MWh in the year following the expiration of the PPAs. [redacted] Over the course of the 10-year extension period, there still would be savings [redacted] Also, as indicated above, the estimate of savings is highly sensitive to the cost of O&M in the outer years, the amount of remaining book assets, and the market prices for similar products.

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[18] ISO New England, Final Scenario Analysis Modeling Assumptions, presentation to a stakeholder meeting, May 21, 2007, p. 28.

[19] Lillian F. Mills, "Tax versus book accounting," *Encyclopedia of Tax Policy*, 2nd Edition, Joseph J. Cordes, Robert D. Ebel, Jane G. Gravelle, Eds., (Washington, DC: The Urban Institute Press, 2005).

[20] Various parts of the Cape Wind project are likely to be depreciated at different rates. For purposes of simplicity and without knowing either the total project cost or the breakdown of project cost by depreciable life, the assumption of an average depreciable life is reasonable.

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[redacted] extending the contract by a 10-year term at an assumed cost-based price would result in estimated savings to ratepayers of approximately $156.8 million (undiscounted and in nominal dollars) over the 10-year extension period, or $24.5 million in NPV terms as of 2013, using National Grid's 7% discount rate to convert the savings into NPV terms.

Q. If the estimated savings is highly sensitive to assumption of O&M costs, capital costs remaining on the books, and market prices at the time of exercising the option, how likely would this option benefit ratepayers.

A. Having the option is definitely valuable and the more uncertain the future is, the more valuable the option is. That is because the option simply caps the price of the contract to the market prices and it would be exercised only if the market prices are higher than the cost-based prices. It is not an obligation to extend the contract.

Also, at least one area where current significant uncertainties may have been resolved in ways that could give the option value is O&M costs. For our calculations, we assumed that O&M expenses would begin at $50/MWh in 2013[21] and would escalate at 3.5% per year throughout the PPA term and subsequent contract extension period. However, since this assumption is at least in part driven by the fact that Cape Wind will likely be the first offshore wind project in the U.S. and that there is no experience and/or infrastructure to support offshore wind projects, O&M expenses may not follow this path if an offshore wind industry were to develop in the Northeast over the next 15 years. If, for example, O&M expenses, due to learning and scale effects associated with an evolving offshore wind industry, were closer to $30/MWh (2013 dollars), the option to extend the contract at cost plus could have significant additional value. Even assuming that O&M expenses of $30/MWh (2013 dollars) were to escalate at 3.5%, *i.e.*, at a rate above inflation

[21] We explain the basis for this assumption below.

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throughout the 25 year life of the project, cost-based pricing based on this lower O&M expense would yield an estimated price of $129/MWh in the first year of the contract extension, approximately $9/MWh below the $138/MWh market price [redacted] In sum, the option to extend the contract always has value to ratepayers in a market with uncertain and volatile prices, and in this case the uncertainty about O&M expenses in particular suggests that the option to extend the contract may have substantial value.

G. The Combined Benefits Of The Amended PPAs Yield An Equivalent PPA Price That Could Be Lower Than Its Comparables

Q. Can you value the likely benefits associated with the conditional downward price adjustments and the option to extend at cost-plus pricing?

A. In principle it is possible to value the benefits associated with the various conditional downward price adjustments in the Amended PPAs. However, because any adjustment depends on observing actual costs, which by definition are not known today, and because the Cape Wind project, being likely the first offshore wind project in the U.S., faces substantial cost uncertainties, deriving a single number for the combined effect of the various cost adjustment mechanisms would be speculative at best. As we have described above, we believe that it is most likely that ratepayers will benefit from a downward adjustment in the PPA price due to a lower borrowing cost. We have indicated that there is some evidence that with a federal loan guarantee the average borrowing cost may drop substantially, perhaps to a value as low as 5%. As previously discussed, the Financing Adjusted Price at a 5% debt cost would be approximately $172.6/MWh in the first year of the PPA and would vary over the PPA term according to the financing cost savings realized in each year as the project debt is repaid. The equivalent levelized nominal price would be approximately $221.0/MWh.

Also as described above, it is less likely that the provision of sharing lower costs due to lower construction expenses will be triggered. Finally, the option to purchase power from the Cape Wind project on a cost plus basis certainly has value (options always do in the presence of uncertainty). As an illustration, we have shown above that if the option to extend the PPA is exercised, and if both our rough estimate of cost plus and the market price forecasts provided by ESAI materialize, ratepayers could save approximately $157 million over the 10-year extension period, or $24.5 million in NPV terms from the contract extension.

Q. How does the proposed pricing in the Amended PPAs compare to the costs of comparable offshore wind projects?

A. As we will show below, the unadjusted Base Price of the Amended PPAs is comparable to prices and costs of comparable offshore wind projects in U.S. However, any of the price adjustments, due to the additional provisions in the Amended PPAs could make the proposed PPAs lower priced than the comparable U.S. offshore wind projects we examined.

VI. THE UNADJUSTED BASE PRICE IN THE AMENDED PPAS IS AT THE HIGH END, BUT WITHIN, THE COST RANGE OF OFFSHORE WIND PROJECTS

A. THE BASE PRICE IN THE AMENDED PPAS IS CONSISTENT WITH THE EQUIVALENT PPA PRICES OF COMPARABLE U.S. OFFSHORE WIND PROJECTS

Q. How does the pricing in the proposed PPAs compare to the comparable costs of other U.S. offshore wind projects?

A. The unadjusted Base Prices of the proposed PPAs are comparable to some of the prices proposed for other U.S. offshore wind projects with publicly-available prices. We estimated Cape Wind's likely cost using publicly-available information on other offshore wind projects in operation or planning, both in the U.S. and abroad. Based on this analysis, we find that the unadjusted Base Prices under the proposed PPAs are comparable to other domestic offshore wind projects.

Q. [redacted]

A. [redacted]

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22 [redacted]

REDACTED

[redacted]

Figure 5

[redacted]

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Q. Did you compare the proposed pricing in the PPAs for Cape Wind to the price of any other U.S. offshore wind projects?

A. Yes. We compared the proposed pricing for Cape Wind to two other offshore wind projects with publicly-available pricing information: the amended Deepwater Block Island PPA and the PPA between Bluewater Wind and Delmarva Power & Light for a 200 MW wind project in offshore Delaware.

Q. How does the proposed price for Cape Wind compare to the pricing in the amended PPA for the 28.8 MW Deepwater Block Island project in Rhode Island?

A. Whether the amended Deepwater Block Island PPA results in a higher or lower price than the proposed PPA for Cape Wind depends on what the project cost ultimately turns out to be. If the actual project cost is lower than the estimated cost indicated in the amended Deepwater Block Island PPA ($7,132/kW), then the price to ratepayers will be reduced according to a price schedule ranging from an initial price of $236/MWh to as low as $190/MWh (in 2012 dollars).[23] If the project were built at its estimated cost, the proposed price is $244/MWh in 2013 dollars, escalating at 3.5% per year for 20 years. Discounting this price stream to the present day using National Grid's stated discount rate (7%), we estimate the levelized cost of the amended Deepwater Block Island PPA to be $320/MWh.

If we adjust the 20-year contract to a 15-year contract, putting it on similar terms as the proposed Cape Wind contract and using the same approach discussed above, the equivalent levelized cost of the Deepwater Block Island PPA is approximately $340/MWh. This price is approximately 48% higher than the $230.4/MWh proposed price for Cape Wind. However, the 28.8 MW capacity of the Deepwater Block Island project would be just 6% of Cape Wind's 468 MW capacity, so the cost of Cape Wind

[23] Deepwater Block Island PPA, Appendix X to Exhibit E.

should be substantially less than the cost of the Deepwater Block Island project on a per-MWh basis considering the economies of scale in wind projects generally. In addition, the RIPUC has already rejected one PPA for the Deepwater Block Island project and only accepted the amended PPA after it was modified in ways that links the price to the actual project costs.

Q. Could you describe the features of the Bluewater PPA?

A. The Bluewater PPA is a 25-year contract for output associated with a 200 MW offshore wind project, with a base energy payment of $98.9/MWh, $70.2/kW-year for capacity, and $15.3 (in 2007 Dollars) per REC, escalated at 2.5% per year for the duration of the contract. Under a condition precedent to the Bluewater PPA, Delmarva, the purchasing utility, would be entitled to receive a 350% credit toward meeting its renewable energy requirement for each REC it purchases from Bluewater project. This policy decision was likely intended to reduce the resulting impact on ratepayers. It effectively allows Bluewater to receive $53.6 per REC for the RECs it would deliver to Delmarva. In other words, for 28.6% of the 200 MW capacity, Bluewater would receive $152.6/MWh for energy and RECs (in 2007 Dollars), and for the remaining 71.4% of the capacity, Bluewater would receive $98.9/MWh for the energy. In addition, Bluewater would receive $70.2/kW-year for the project's 200 MW capacity. At the project's assumed capacity factor of 31.91%, this capacity price is equivalent to $25.1/MWh. Further, Bluewater would be free to sell the remaining RECs to the market. [24]

[24] Report on Final Power Purchase Agreement Between Delmarva Power and Bluewater Wind Delaware LLC, before the Public Service Commission of the State of Delaware, in the matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL C. §1007(c) & (d): Review and Approval of the Request for Proposals for the Construction of New Generation Resources Under 26 DEL. C. §1007(d), PSC Docket No. 06-241, July 3, 2008.

Q. Based on the unique feature of the Bluewater PPA, what would be the cost of the Bluewater contract to ratepayers of Delmarva?

A. Overall, the equivalent cost of the PPA to Delmarva ratepayers is $139/MWh in 2007 Dollars, escalated at 2.5% per year. This cost takes into account that for each REC that Delmarva purchases from Bluewater, it would receive 350% credit.

Q. Given that Bluewater can sell on the market the RECs not delivered to Delmarva , wouldn't Bluewater and Delmarva ratepayers benefit from market REC sales too?

A. Yes, the provision that allows Delmarva to take 350% credit for each REC it purchases from Bluewater benefits the ratepayers of Delmarva by allowing them to obtain more value for the price they pay for the PPA. From Bluewater's perspective, the sale of the remaining RECs on the market also can add to the project's revenues. If we assume that Bluewater can receive the same value per REC as they do from the PPA with Delmarva, Bluewater could, at least in theory, collect another $15.32/REC for each REC not sold to Delmarva.[25] Spreading this value over the total output from the project, this would add about another $10.94/MWh. Thus, overall, the revenue that Bluewater would receive (assuming the market price of RECs is $15.32) would amount to $150.3/MWh in 2007 Dollars. After escalating this price by 2.5% per year (from 2007 to 2013), the amount that Bluewater would receive in 2013 is equivalent to $174.3/MWh.

Q. How does the Cape Wind PPA price compare to the pricing in the Bluewater PPA?

A. [redacted]

[25] It is worth noting that the Futures' prices for New Jersey (which is located in PJM, the same wholesale energy market as Delaware, and where the Bluewater RECs can be sold) Compliance Renewable Energy Credits are in the $3.00 to $5.00/REC range through 2016. Therefore, an assumption of $15.32/REC is relatively high for the value of the remaining RECs that Bluewater might receive from the market. (See Chicago Climate Futures Exchange (CCFE), www.ccfe.com.)

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[redacted] The Bluewater PPA starts at an initial PPA price of $174/MWh and escalates at 2.5% per year for 25 years.[26] Discounting this price stream to the present day using National Grid's stated discount rate (7%), the levelized cost of the Bluewater PPA is $209/MWh. But since the Bluewater PPA has a longer term and a lower escalation rate, we adjusted this contract to a similar term and escalation rate as the Cape Wind PPA, again using the approach outlined above. We derived an equivalent starting price of about $187/MWh escalating at 3.5% per year, and a corresponding levelized cost of about $230.6/MWh. This adjusted Bluewater PPA price is therefore very close to the levelized price of $230.4/MWh for the proposed Cape Wind PPA.

Q. Are there other features in the Bluewater PPA that would help protect the ratepayers of Delmarva?

A. Yes, like the amended National Grid-Cape Wind PPA (*i.e.*, Amended PPA 1), the Bluewater PPA also has a "most favored customer pricing" clause. Under the provision, if Bluewater enters into a PPA with a third party for the sale of the same products from the same project, or from any other offshore wind projects within 50 miles from the project, prior to financial closing of the project, Bluewater must offer the more favorable terms and conditions to Delmarva.[27]

Q. In summary, how does the price of the proposed Cape Wind–National Grid PPAs compare to other offshore wind projects in the U.S.?

A. Table 5 summarizes proposed pricing [redacted] Compared with the adjusted prices of the Cape Wind–National Grid PPA, the [redacted] unadjusted Base Price

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[26] Power Purchase Agreement between Delmarva Power & Light Company ("Buyer") and Bluewater Wind Delaware LLC ("Seller"), June 23, 2006 (Bluewater PPA).

[27] Power Purchase Agreement between Delmarva Power & Light Company ("Buyer") and Bluewater Wind Delaware LLC ("Seller"), June 23, 2006 (Bluewater PPA).*Ibid.*

and the adjusted levelized Bluewater PPA price (along with REC market revenues) is comparable to the Base Price in the amended PPAs.

Table 5
Comparison of Cape Wind to U.S. Offshore Wind Projects

		[redacted]	Bluewater	Cape Wind[1]	Deepwater Block Island[1]
Term	years		25	15	20
Capacity	MW		200	468	28.8
Estimated Project Cost	$/kW		unknown	unknown	$7,132
Stated prices					
Initial Price	$/MWh		$174	$187	$244
Price escalation	%/year		2.5%	3.5%	3.5%
Levelized Price	$/MWh		$209	$230	$320
As % Cape Wind			*91%*	*100%*	*139%*
Adjusted prices					
Initial Price	$/MWh		**$187**	**$187**	**$276**
Levelized Price	$/MWh		**$231**	**$230**	**$340**
As % Cape Wind			***100%***	***100%***	***148%***

Assumes all projects qualify for ITC. [1] Assumes no cost savings or resulting price reductions.

Q. What are your findings based on the prices in Table 5?

A. Based on the prices in Table 5, we find it important to note that Cape Wind's unadjusted Base Price somewhat exceeds the price of the only U.S. offshore wind PPA approved to date (Bluewater) [redacted] the adjusted levelized Bluewater PPA price is essentially the same as Cape Wind's levelized price. [redacted] more expensive than the unadjusted Base Price of the Amended Cape Wind PPA is the Deepwater Block Island project at its estimated cost. However, as we discussed above, the potential price adjustments due to observed elements of project costs make it likely that the amended PPA will result in prices that are comparable or lower than the prices under other proposed offshore wind projects in the United States of broadly similar size.

B. The Base Price in the Amended PPAs is Slightly Higher Than the Comparable Cost of Offshore Wind Projects Abroad

Q. How does the proposed price for Cape Wind compare to the costs of offshore wind projects outside the U.S.?

A. The unadjusted Base Price of the Amended PPAs is slightly more expensive than the costs observed for offshore wind projects outside of the U.S. would suggest. However, after incorporating the potential price reductions contemplated in the Amended PPAs, we find that the implied project cost associated with Cape Wind would be within a reasonable range of the offshore wind project outside of the U.S.

While there are less than a handful of U.S. offshore wind projects, and none in operation, there are many offshore wind projects outside of the U.S. In the initial Deepwater Block Island proceeding, Deepwater's pre-filed testimony included information on the comparable costs of offshore wind projects abroad.[28] Exhibit AG-JWJC-5 lists each of these projects by country, status, first year of operation, and capacity. Presently, there are at least 59 offshore wind projects with a capacity of 5,742 MW in operation, under construction, or being financed outside of the U.S. There are 43 projects with a capacity of 2,207 MW in 12 countries (almost entirely in Europe) already in operation. Nine other projects representing 1,818 MW of offshore wind capacity, also in Europe, have been financed and are under construction, and seven more projects representing another 1,718 MW have secured financing.

[28] See Nickerson Testimony, Exhibit B. See also New York State Energy Research and Development Authority (NYSERDA), *New York's Offshore Wind Energy Development Potential in the Great Lakes: Feasibility Study*; Final Report 10-04, April 2010 (NYSERDA Report).

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Project cost information is not publicly available for all of these projects. Exhibit AG-JWJC-6 summarizes the available cost data. We were able to identify cost data for 25 offshore wind projects outside of the U.S., including 17 projects in operation and all seven of the projects that have been financed but not yet built. Over all projects with cost data, project costs range from $1.3 million per MW to $5.8 million per MW. On average, project costs are approximately $3.4 million per MW. Our base case estimated project costs for Cape Wind is approximately $5.6 million per MW, or higher than all but the highest cost project on Exhibit AG-JWJC-6.

Q. Does this comparison allow for an assessment of Cape Wind's proposed pricing relative to the cost of comparable projects?

A. The direct cost comparison is a starting point for considering the relative cost of the proposed PPAs because it reflects the actual cost implied by the pricing proposed in the PPAs discounted to the present. However, to make a more precise comparison to other offshore wind projects requires adjustment for differences in the characteristics of the projects that have cost implications, such as a project's distance from the shore, water depth, and number of turbines. These factors likely significantly influence project costs. Therefore, we adjusted the observed project costs to render them comparable to the same characteristics of the Cape Wind project.[29] Exhibit AG-JWJC-7 shows the results of this simple analysis for each of the 25 projects listed on Exhibit AG-JWJC-6. The resulting range of adjusted costs is $1.3 million per MW to $4.8 million per MW. On average, project costs are $3.3 million per MW (if these projects were sited in a similar situation as the Cape Wind projects. At an assumed cost of approximately $5.6 million per MW,

[29] Specifically, we adjusted for depth and distance, for which scale factors were publicly-available. For Cape Wind, we used an average water depth of 25 feet, calculated as the simple average between 10 feet and 40 feet, and we converted this average to meters. Also adjusting for scale would yield even lower adjusted costs, since Cape Wind would be larger than all but one of the European wind projects.

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Cape Wind would be more costly than these projects, assuming that the adjustments we made are accurate and capture all relevant differences between the various projects.

C. Comparison of Offshore Wind Projects Outside of the U.S. Provides a Benchmark But May Be Imperfect

Q. Why do the costs associated with European offshore wind projects serve as a benchmark for Cape Wind's PPA prices?

A. There are many more offshore wind projects in Europe than are being planned in the U.S. There is significantly more experience for some of the European developers, and therefore the market for developing offshore wind projects is likely to be competitive enough to yield costs that reflect a competitive market. However, there are also some reasons why these comparisons are not perfect and therefore results should only reflect a benchmark. They are not necessarily directly comparable.

Q. What are some of the reasons that a comparison with European offshore wind project costs is imperfect?

A. There are several factors that a direct comparison does not take into consideration. Different countries or localities may provide different incentives to develop offshore wind projects. Those incentives may come in the form of reduced taxes, but also in subsidies of other kinds that may reduce the developers' costs. Siting of offshore wind projects may also face different environmental or other local scrutiny, making projects less costly to site in some areas than others. In addition, with significantly more experience, some European developers may be able to reduce their project cost by purchasing materials and equipment in large quantities and/or by outsourcing operations and maintenance services in large volumes. Further, since most of the larger equipment such as the turbines and blades are currently manufactured in Europe, European projects are likely to benefit from lower transportation costs. Finally, any comparison of costs between European and U.S.-based projects will suffer from the complexities associated with varying exchange rates. Over the past several years, the ratio of the U.S. dollar to the Euro has fluctuated substantially and any comparison of project costs would likely suffer from effects related to exchange rate fluctuations.

VII. THE PROPOSED UNADJUSTED BASE PRICE IS CONSISTENT WITH CAPE WIND'S LIKELY COST

Q. Did you estimate Cape Wind's likely cost?

A. Yes we did.

Q. How did you derive estimates of the project's costs?

A. In addition to comparing Cape Wind's proposed pricing to the cost of other projects as we have done, it is important to understand how the proposed prices relate to the project's own costs. Having compared Cape Wind to other offshore wind projects in the U.S. and abroad, we collected cost information about offshore wind which we used to estimate Cape Wind's likely project costs. Specifically, we used the available cost data to derive a range of estimates for Cape Wind's likely installed cost, financing cost, and future Operating and Maintenance (O&M) expenses.

Q. How did you use these cost inputs to evaluate the proposed pricing in the PPAs?

A. We used these cost inputs to estimate the contract prices which reflect Cape Wind's estimated cost, which we compared to the proposed pricing in the PPAs to determine whether the proposed pricing reasonably reflects Cape Wind's project costs or would generate a windfall for the project.

We derived the contract prices which reflect Cape Wind's estimated cost using a simplified discounted cash flow model (DCF) of the Cape Wind project. This is a slightly different analytic approach from the levelized cost comparisons we have discussed so far. The typical levelized cost approach estimates the constant amount of annual revenue that is required to pay for the costs of a project, including interest and principal on debt financing and a return to equity financing for the life of the project. However, in this case, the proposed 15-year PPA would not constitute the only source of revenue available to Cape Wind, since the project's expected life exceeds the contract term after which the project will realize market revenue. Therefore, we simulated Cape Wind's expected future revenue and costs in a DCF framework. DCF is used widely in business and litigation contexts to value assets or for planning purposes. By solving the DCF for the stream of contract prices which yield a net present value (NPV) of net cash flows just equal to the project's installed cost, we can estimate the implied contract prices that reflect the project's estimated construction, financing, and O&M costs. Comparing the resulting implied contract prices to the proposed prices in the PPAs allows us to assess the reasonableness of Cape Wind's proposed prices relative to the project's estimated cost.

Q. What is your estimate of Cape Wind's likely installed cost?

A. We estimate Cape Wind's installed cost to be approximately $5,600/kW. We considered two separate sets of information in deriving our installed cost estimate for Cape Wind.

Q. Please describe the first set of information you considered.

A. First, we reviewed several reports containing cost estimates for offshore wind projects. These reports include: a) an Ernst & Young report entitled "Cost of and financial support for offshore wind" (E&Y Report), prepared on April 27, 2009 for the U.K. Department of Energy and Climate Change; b) a NYSERDA report entitled "New York's Offshore Wind Energy Development Potential in the Great Lakes, A feasibility study" (NYSERDA Report); and c) a report prepared by Navigant Consulting, entitled

"Massachusetts Renewable Energy Potential" August 2008, for Department of Energy Resources and Massachusetts Technology Collaborative (MTC), (DOER Study).

The E&Y report shows that the total capital costs in the U.K. have been increasing steadily since 2006 and are expected to reach £3.2 million/MW for projects expected to reach commercial operation by 2012, hence closer to the expected in-service date for Cape Wind. As we have discussed above, it is not straightforward to compare this cost to the proposed PPAs as it is in a different currency and may not include the full cost of transmission[30] to connect such projects to the U.K. electric grid. Also, it is unclear whether all other relevant costs are included in the planning and development costs, which E&Y estimates at 12% of total capital costs. At an exchange rate of $1.5027/£,[31] £3.2 million/MW is equivalent to $4.8 million/MW and substantially lower than our $5,600/kW installed cost figure.

Our project cost estimate is relatively high when compared to the range of project costs in Exhibit AG-JWJC-6, which reproduces the project costs contained in the NYSERDA

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[30] Ernst & Young, *Cost of and financial support for offshore wind*, A report for the Department of Energy and Climate Change, URN 09D/534, 27 April 2009 (E&Y Report). The report lists the cost of electrical infrastructure as £0.6 million per MW or 19% of total project cost (p.5). On p. 8, the report relates the electrical infrastructure costs to the distance from shore and finds that these costs increase significantly with distance, suggesting that transmission is at least partially included. P. 8 also discusses how recent increases in this part of total project costs relate to the fact that more recent offshore wind projects have been built/planned further from shore. On p. 15, the report discusses the impact of the Offshore Transmission Operator (OFTO) regime on levelized costs. Since the OFTO is responsible for building, financing, and operating the transmission system linking an offshore wind facility to the on-shore grid, it is likely that E&Y's electrical infrastructure capital costs include the transmission link to shore. Under the transitional regime in place for projects currently under construction, the offshore wind developer is responsible for building the transmission link, which it then assigns to the winner of the currently active tender process for transitional OFTOs (see Overview of Great Britain's Offshore Electricity Transmission Regulatory Regime, JOINT DECC/OFGEM STATEMENT, June 17, 2009, p.13 and Ofgem website (www.ofgem.gov.uk) re information on the currently active Round One Transitional Tenders).

[31] As of 7/13/2010 per http://www.exchange-rates.org/Rate/GBP/USD/7-12-2010.

report[32] and Exhibit AG-JWJC-7, which adjusts these estimates for depth and distance from shore. As discussed before, even with the caveat of the difficulties of translating European project costs from multiple years into comparable project costs for Cape Wind, our cost estimate is significantly higher than those described in the NYSERDA report.

The DOER Report uses an assumption of $5,400/kW of installed cost for a hypothetical 300 MW offshore wind project. It also assumes that the cost of such a project may decrease, with a range of installed cost of between $4,990/kW and $5,296/kW, by 2012 (in 2008$).

Q. Please describe the second set of information you considered.

A. The second set of information we considered included confidential information [redacted]

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32 NYSERDA Report, p. 153.

33 [redacted]

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[redacted]

Based on the information above, we estimate Cape Wind's overall project cost to be approximately $5,600/kW. Since this project may be one of the first offshore wind project installed in the U.S., $5,600/kW is a reasonable estimate for total capital cost.

Q. What are your estimates of Cape Wind's likely O&M expenses?

A. We determined that a reasonable range for offshore wind O&M expenses is approximately $30/MWh to $50/MWh, escalating at an annual rate of between 2.5% and 3.5% (*i.e.*, increasing at or slightly above the expected inflation rate). This estimate is based on a combination of publicly-available information and Europe's experience with offshore wind projects.

Some studies estimate offshore wind O&M expenses will be three to five times as high as O&M expenses for on-shore wind projects.[37] E&Y[38] estimates the O&M expense for offshore wind projects in the U.K in 2009 at £79,000/MW per year. At an exchange rate of $1.5027/£,[39] this translates into a cost of $36.50/MWh at a capacity factor of 37.1%.

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35 [redacted]

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37 See, *e.g.*, Steve Kopits and Adam Westwood, "Offshore Wind: Time for a Market Take-off?," *Renewable Energy World International*, September/October 2009, Vol. 12(5).

38 E&Y Report, p. 8.

39 As of 7/13/2010 per http://www.exchange-rates.org/Rate/GBP/USD/7-12-2010.

Including decommissioning costs, assumed by E&Y to be £18,000/MW per year,[40] the assumed total O&M expense would be approximately $45/MWh. A study prepared by NYSERDA in April 2010 reports O&M expenses for offshore wind projects ranging from $30/MWh to $50/MWh.[41] [redacted]

Taking all this information into account and recognizing, as some of the sources cited above do, that the estimation of O&M expenses for offshore wind projects is potentially one of the most difficult aspects of offshore wind project cost estimation, and also recognizing that this is particularly true for the first U.S. offshore wind project, we have assumed that estimated O&M expenses should be at the upper end of this range and have therefore used an O&M cost estimate of $50/MWh (or $162.50/kW year), escalating at 3.5% per year.

Q. What are your estimates of Cape Wind's likely financing costs?

A. We estimated Cape Wind's financing cost based on 70% debt financing at a 7.5% cost of debt and 30% equity financing at a 18% cost of equity. We have reviewed several public industry reports in estimating these financing costs. First, we find that the leverage ratio for a renewable energy project, including offshore wind projects, is typically between

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40 E&Y Report, p. 10. This number also includes normalized pre-OFTO Transmission Network Use of System charges (TNUoS).

41 NYSERDA Report, Section 10, p. 157.

42 [redacted]

55% and 80%.[43] We find that financing 70% of the project with debt is consistent with [redacted] a report on Cape Wind by the Minerals Management Service (MMS).[45] We also observe that bank debt financing for renewable energy projects tends to have an interest rate of about 7% to 7.5%.[46] We recognize that the recent financial crisis has likely had at least a temporary impact on interest rates. For example, Mr. Stoddard's testimony, provided to us in response to a discovery request, argues that recently the borrowing cost for a merchant power project may have been as high as 8.84%.[47] While Mr. Stoddard's testimony in that case did not address the cost of borrowing for an offshore wind project with a long-term contract, it does point to the fact that interest rates may change substantially over the short term. However, using estimated recent yields on corporate bonds likely overstates the interest rate on debt for a project like Cape Wind for two reasons: First, it reflects an "echo effect" of the bottom of the financial crisis, *i.e.*, interest rates that reflect a relatively short-term phenomenon rather than longer-term "normal" interest rates; and second, the high interest rate assumption ignores the impact of the prospect of receiving a federal loan guarantee.

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43 Mortimer Menzel (Augusta & Co.), "Sourcing and Deploying Capital in Renewables," presented to the Renewable Energy Financing Forum (REFF London), September 2009 (Menzel REFF Report) and Christopher Knowles (European Investment Bank), "EIB: Offshore Wind & Economic Recovery," presented at BWEA Offshore Wind 2009, June 2009.

44 [redacted]

45 Robert S.D. Mense, "Draft Evaluation of the Cape Wind Project Proposed Site and Alternatives with the Offshore Wind Energy Project (OWEP) Model; A Microsoft Excel Cash Flow Spreadsheet," Economics Division, Minerals Management Service (MMS Report), May 25, 2007, which assumes a 75% share of debt. (p. 9)

46 World Economic Forum, "Green Investing: Toward a Clean Energy Infrastructure," REF: 200109, January 2009, p. 24.

47 Cape Wind's Response to the Attorney General's Second Set of Information Requests (Cape Wind's 2nd IR Responses), AG 2-2, Attachment CW-AG-2-2(a), pp. 93-94.

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Combining these factors, we decided to use an interest rate of 7.5%, on the higher end of the typical range of interest rates for merchant projects absent a financial crisis and loan guarantee programs, but also consistent with an expected combination of the lingering effect of the financial crisis and the likely receipt of federal loan guarantees. Finally, we applied a cost of equity of 18%.[48] While the cost of equity can vary based on the type of investor, an 18% cost of equity for a merchant renewable energy generation company exceeds the normal range of equity costs. For example, Mr. Stoddard's testimony reports the average cost of equity to be less than 15%, but also suggests that higher equity costs may apply to some riskier projects.[49] There is some indication that if Cape Wind receives a federal loan guarantee,[50] its cost of debt could be significantly below 7.5%, thus reducing its overall cost of capital. The Amended PPAs recognize this fact and provides for adjustments in the PPA price if borrowing costs fall below 7.5%.

Q. Did you have to develop other inputs in order to estimate the price range that reflects Cape Wind's estimated costs?

A. Yes. We used information provided by National Grid in assuming the amount of market revenue Cape Wind can expect to realize for energy, capacity, and RECs after the 15-year PPA expires.[51] We assumed an expected project life for Cape Wind of 25 years, or 8 years beyond the expiration date of the PPA, assuming a two year construction period.[52]

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48 Menzel REFF Report and Mortimer Menzel (Augusta & Co.), "A Developer's Access to Equity Capital: Public vs. Private," presented to the European Wind Energy Conference, Brussels, April 2, 2008.

49 Cape Wind's 2nd IR Responses, AG 2-2, Attachment CW-AG-2-2(a), pp. 93-94.

50 Cape Wind's Response to the Attorney General's Third Set of Information Requests (Cape Wind's 3rd IR Responses), AG -3-6, where Cape Wind states that it plans to apply for a DOE loan guarantee. [redacted]

51 We use the ESAI forecast, Exhibit MNM-3 to Milhous Testimony.

52 Including 2 years of construction, or 23 years of operation post completion. (U.S. Department of the Interior Minerals Management Service Environmental Division (MMS), *Renewable Energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf: Final Rule*, Environmental Assessment, OCS

We also assumed: 37.1% capacity factor; both contract prices and O&M expenses escalate at 3.5% rate per year; the project qualifies for an ITC equal to 30% of the project cost eligible for accelerated depreciation, which in turn reduces the depreciable (tax) asset base by half the ITC and that the ITC could be recovered over a two-year period;[53] a tax rate of 35%; and 5-year modified accelerated tax depreciation for 95% of the project cost.[54] Finally, we assumed the Cape Wind project would receive capacity credit at 26% of its installed capacity in years after the expiration of the PPA.[55] Table 6 summarizes the Baseline inputs we used to estimate Cape Wind's costs.

EIS/EA, MMS 2009-026.) Mr. Milhous estimates price suppression benefits of the projects of 25 years. Even if, as we discuss below, we question the magnitude of this benefit, price suppression can only occur while the project is generating electricity. Hence, proponents' testimony itself includes the assumption that Cape Wind would operate for 25 years, not 23 years. In addition, it is at least possible that at the end of the federal land lease a renewal would be negotiated and that the project life would thus be further extended. The relicensing of nuclear power plants is one example of the life of power plants far exceeding original expectations or authorizations.

53 The economics of a project like Cape Wind depend significantly on the value of the ITC, which in turn depends on the ability to absorb the tax credit in a timely manner. For the tax equity investors in Cape Wind to receive the maximum benefit from the ITC, they would collectively need to be able to absorb an ITC of close to $1 billion in a single year, which in turn implies needing a federal tax liability of at least that amount. As a result of the recent financial crisis, the amount of tax equity capable of absorbing this high a tax credit in a single year has likely declined. It is therefore possible that the ITC will need to be recovered over multiple years. We have therefore assumed that the ITC would be recovered over a 2-year period. For a discussion of the impact of the financial crisis on the availability of tax equity, see also Mark Bollinger, Ryan Wiser, Karlynn Cory and Ted James, "PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States," NREL/TP-6A2-45359, March 2009.

54 Not all project costs qualify for accelerated depreciation. For example, it is our understanding that the transmission infrastructure investments would not qualify for accelerated depreciation (and hence not for the ITC). At $108 million, the transmission investment equals roughly 3% of the total project cost. We assumed that some additional project costs would also not qualify and hence excluded 5% of the project costs from ITC and accelerated depreciation. For simplicity, we assumed that the same 5% would not benefit from any depreciation allowance.

55 ISO New England, Final Scenario Analysis Modeling Assumptions, presentation to a stakeholder meeting, May 21, 2007, p. 28.

Table 6
Cape Wind Estimated Cost Inputs in $2013

Installed cost	($/kW)	$5,600
O&M	($/MWh)	$30 to $50
O&M escalator	%/year	3.5%
Capacity factor		37.1%
Project life	years	25
Contract term	years	15
Escalation factor	%/year	3.5%
Initial cash outlay	$/year	50% for 2 years
Debt financing		70% @ 7.5%
Equity financing		30% @ 18%
ITC		Yes, 30%
Tax rate		35.0%
Tax depreciation		5-year MACRS on 95% of installed cost

Q. Based on these inputs, what price reasonably reflects Cape Wind's estimated cost?

A. Based on the inputs summarized in Table 6, we estimated that the initial price for the first year of the PPA which reasonably reflects Cape Wind's costs (including a reasonable return to its equity investors) is approximately $188.9/MWh. The corresponding levelized price over 15 years is $232.7/MWh. Table 7 shows these prices and Exhibit AG-JWJC-8 provides our detailed discounted cash flow projection for Cape Wind. This estimated price is slightly higher than the unadjusted Base Price assuming a 468 MW Cape Wind project, and slightly below the Maximum Base Price for a project of 396 MW or less, but is generally consistent with the potential range of Base Prices under the Amended PPAs.

Table 7
Implied Cape Wind Pricing in $2013

	Fixed O&M ($/MWh)	
	$30	$50
Initial price	$162.99	**$188.89**
Levelized price	$200.83	**$232.74**

Prices are $/MWh based on the inputs in Table 6.
Levelized using National Grid's stated discount rate of 7%.

Q. Is it possible that the financing cost of Cape Wind will be higher than you assume?

A. It is possible, but based on all the information we reviewed it seems unlikely. The impact of receiving a 15-year PPA and the likely receipt of a federal loan guarantee, plus continued recovery from the financial crisis, make our price estimate relatively high. However, we acknowledge that the actual financing costs will only be known with certainty if and when the project receives actual financing. Under the Amended PPAs, ratepayers are protected from the risk of higher financing costs since the PPA Base Price cannot exceed $187/MWh (or $193/MWh with a smaller project size) in year 1, escalating at 3.5%, and in turn benefit from lower financing costs, in particular lower borrowing costs, through the PPA Price adjustment mechanism described above.

Q. What do you ultimately conclude from your analysis of the estimated cost for a project such as Cape Wind?

A. All things considered, our analysis of the estimated costs for a project such as Cape Wind shows that the unadjusted Base Price under the Amended PPAs is broadly in line with a reasonable estimate of Cape Wind’s project costs. Any estimate of the cost of Cape Wind must by definition be quite uncertain, given the lack of experience with offshore wind projects in the United States. The most likely sources of any difference between actual project cost and the cost we estimate lie in changes to borrowing costs, O&M expenses, and construction costs. Of these three factors, ratepayers are partially protected from overpaying for a Cape Wind project that benefits from costs that are lower than those that we assume and which make the unadjusted Base Prices of the Amended PPAs seem reasonably related to estimated project costs.

The most important driver of any cost savings are lower borrowing costs. Ratepayers will share significantly in any cost savings related to lower borrowing costs. Ratepayers are also protected against large differences between projected and actual construction costs. Finally, while savings due to lower O&M expenses will not result in immediate ratepayer benefits, O&M expenses are a difficult element of Cape Wind's costs to estimate, and may be most impacted by the fact that Cape Wind will likely be the first (and for several years only) offshore wind project in the region. Ratepayers do however benefit from lower O&M expenses through the option to extend purchases for a ten-year period after the end of the initial PPA since the pricing under the extension option is directly tied to observed and independently verified O&M expenses. In sum, in our opinion, the pricing (both base pricing and price adjustments) under the Amended PPAs reasonably reflect the likely costs of Cape Wind as a project as well as the uncertainties associated with estimating major drivers of Cape Wind's cost prior to completion of the project.

VIII. CONCLUSIONS

Q. Based on all of the foregoing discussion, what conclusions did you ultimately draw?

A. Based on the analyses contained in this testimony, we draw several conclusions.

First, the Amended PPAs are a significant improvement over the PPA originally filed. It results in a significantly lower Base Price, which by itself lowers costs for National Grid ratepayers by between $400 and $600 million over the 15-year contract term, resulting in a net present value of savings between $240 million and $340 million.

Second, the Amended PPAs also recognize that a number of drivers of a project like Cape Wind are highly uncertain at this time of PPA negotiations. Consequently, the Amended PPAs now include several adjustment mechanisms that give ratepayers a significant share in any cost savings as a result of lower financing costs, construction costs, and to some extent even O&M costs. In our opinion, the Amended PPAs represent the type of contract that should be employed more frequently when relatively new technologies with significant cost uncertainties are involved.

Third, the unadjusted Base Price under the Amended PPAs is consistent with the prices for comparable offshore wind contracts [redacted] in the United States. Even without assuming that any of the events that would trigger further reductions in the PPA price will occur, the Base Price is within the reasonable range of comparable prices of other U.S. offshore wind projects.

Fourth, the unadjusted Base Price is also somewhat higher than the price that would reflect the expected costs of offshore wind projects in Europe, where more experience with such projects exists. Given the difficulties in comparing European with U.S. projects (resulting from the different state of the offshore wind industry) and given confounding trends towards higher costs for wind projects overall, the terms of the Amended PPAs are reasonably within the range of observed project costs in Europe, especially once the potential PPA price reductions under the Amended PPAs are taken into account.

Fifth, the Amended PPA unadjusted Base Price is consistent with our own estimate of Cape Wind's likely project cost.

Finally, with both unadjusted Base Prices and potential downward adjustments, the Amended PPAs compare favorably to alternative offshore wind projects. The unadjusted

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Base Price is consistent with [redacted] contracts of comparable projects, and our estimate of likely project costs. The various adjustment mechanisms provide a model for allowing a sharing of risks and rewards related to the signing of long-term contracts for projects with highly uncertain cost elements.

Q. Does this conclude your testimony at this time?

A. Yes. Thank you.

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Dr. Jürgen Weiss heads the firm's climate/carbon practice. He specializes in climate change and carbon market analyses, renewable energy, and electric utility economics. He has significant experience in the development and application of economic and financial models to analyze the impact of proposed rules and regulation on business practices, cash flows, incentives, and the value of power assets and related contracts.

His consulting and expert testimony experience has focused on climate change policy implications for utilities and energy-intensive industries. He advises clients on changes in the value of existing assets, transmission flow patterns and capacity adequacy, integration of renewables, market design and performance analysis, and efficient retail incentives and rate design. He brings institutional knowledge of successful climate practices as well as potential pitfalls from his experience with European efforts to reduce CO_2 emissions.

Dr. Weiss has consulted and written substantially on issues related to carbon pricing and the demand side of electricity markets, including topics such as efficiency, conservation, storage, retail rates, renewable power, and Renewable Portfolio Standards. He has also testified in state and federal court, as well as in state regulatory proceedings.

Prior to joining *The Brattle Group*, Dr. Weiss was a co-founder and managing director of Watermark Economics. In addition, he was previously the managing director of Point Carbon's global advisory practice and a director at LECG. He began his career as an associate with *The Brattle Group.*

Dr. Weiss holds an MBA from Columbia University and a Ph.D. in Business Economics from Harvard University.

AREAS OF EXPERTISE

- *Climate Change and Carbon Economics*
- *Renewable Energy and Energy Efficiency*
- *Electric Power*
- *Market Design and Regulatory Policy*
- *Valuation*

PUBLICATIONS

"What Does Copenhagen Mean for Investments in Low-Carbon Technologies?," Jürgen Weiss, in *The Journal of Environmental Investing*, Beyond Copenhagen, Vol 1, No. 1 (2010), www.thejei.com.

"Using Storage to Capture Renewables: Does Size Matter?," Jürgen Weiss, Judy Chang, and Kathleen Spees; presented at the 15th Annual POWER Conference on Energy Research and Policy, The Energy Institute at Haas, University of California Berkeley, 2010

Comment on "After COP 15, who or what will drive the push towards developing clean energy?," Jürgen Weiss, *Comment: Visions*, January 2, 2010, http://www.commentvisions.com/month/february/2010/visions_from#2

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TESTIMONY

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Expert Report of Dr. Jurgen Weiss in *MC ASSET RECOVERY, LLC, Plaintiff, v. THE SOUTHERN COMPANY, Defendant, CIVIL ACTION No. 1:06-CV-0417-BBM* (December 2007).

Deposition in *re: Welding Rod Products Liability Litigation, Case No. 1:03-CV-17000 MDL Docket No. 1535* (May 2005).

Deposition in *Tractebel Energy Marketing, Inc., Plaintiff, against AEP Power Marketing, Inc., American Electric Power Company, Inc., and Ohio Power Company, defendants, 03 CIV.6731(HB)(JCF); and Ohio Power Company and AEP Power Marketing, Inc., Plaintiff, against Tractebel Energy Marketing, Inc. andTractebel S.A. (now known as Suez-Tractebel S.A.), Defendants. 03 CIV.6770(HB)(JCF)* (March 2005).

Preliminary Expert Witness Declaration of Jurgen Weiss, Ph.D. in *re: Welding Rod Products Liability Litigation, Case No. 1:03-CV-17000 MDL Docket No. 1535* (February 2005).

Rebuttal Report of Dr. Jurgen Weiss in *Tractebel Energy Marketing, Inc., Plaintiff, against AEP Power Marketing, Inc., American Electric Power Company, Inc., and Ohio Power Company, defendants, 03 CIV.6731(HB)(JCF); and Ohio Power Company and AEP Power Marketing, Inc., Plaintiff, against Tractebel Energy Marketing, Inc. and Tractebel S.A. (now known as Suez-Tractebel S.A.), Defendants. 03 CIV.6770(HB)(JCF)* (February 2005).

Direct Testimony of Dr. Jurgen Weiss in *Petition and tariff filing of Green Mountain Power Corporation re:proposed rate design changes to take effect January 1, 2005,* in front of the Vermont Public Service Board, Docket No. 6958 (December 2004).

Prefiled Surrebuttal Testimony of Dr. Jurgen Weiss in *Petition and tariff filing of Green Mountain Power Corporation re: proposed rate design changes to take effect January 1, 2005,* in front of the Vermont Public Service Board, Docket No. 6958 (November 2004).

Prefiled Testimony of Dr. Jurgen Weiss in *Petition and tariff filing of Green Mountain Power Corporation re: proposed rate design changes to take effect January 1, 2005,* in front of the Vermont Public Service Board, Docket No. 6958 (August 2004).

Expert Report of Dr. Jurgen Weiss in *Keith Lemon and Lori Lemon, Plaintiffs, vs. Daniel P. McNeil and West Lynn Creamery, Defendants,* in Superior Court of the Commonwealth of Massachusetts, (August 2004).

Direct Testimony of Dr. Jurgen Weiss in *Investigation into General Order No.45 filed by Vermont Yankee Nuclear Power Corporation re: proposed sale of Vermont Yankee Nuclear Power Station and related transactions,* in front of the Vermont Public Service Board, Docket No. 6545 (2002).

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August 19, 2010

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Ms. Judy Chang is an energy economist and policy expert with a background in electrical engineering and over 14 years of experience in advising power companies and project developers with regulatory and financial issues. In the past five years, Ms. Chang has been involved primarily on economic and policy issues around renewable energy planning and deployment. She also has significant experience in transmission-related analyses, including estimating electricity prices in a variety of electricity wholesale markets. In addition, she assists clients on issues of market design, asset valuation, finance, and regulatory policies.

Ms. Chang has submitted expert testimonies to the U.S. Federal Energy Regulatory Commission on capacity markets and reactive power issues and has written numerous testimonies and articles detailing the economic analyses of energy market designs and transmission planning issues, including how the integration of renewable energy might affect electricity markets.

Ms. Chang has also spent several years in India working with global organizations in evaluating and financing renewable energy investments. She received her Bachelor of Science in Electrical Engineering at University of California at Davis and her Master's of Public Policy at Harvard Kennedy School.

AREAS OF EXPERTISE

- *Renewable Energy, Demand-Side Efficiency, Climate Change Consulting*
- *Electric System Modeling*
- *Regulatory and Market Design Issues*
- *Asset and Contract Valuation*

EXPERIENCE

Renewable Energy Engagements, Demand-Side Efficiency, Climate Change Consulting

- For a group of utilities in Midwest, developing a long-term view on the supply and demand balance of generation and demand resources, including the possible high penetration of renewable energy resources and various conventional generation retirement scenarios. The long-term projection will be used in developing transmission infrastructure for the region.

- For a utility in the West, assisting in the development of analytical method to evaluate the operational impact of various levels of wind penetration and estimate the potential need for and costs of ancillary services to help integrate variable generation resources.

- For the Connecticut utilities, analyzed the New England renewable energy market including a detailed evaluation of short-term and long-term supply and demand balance renewable energy in the region, an examination of the supply potential in the region and the potential effect of transmission investment choices on renewable energy development in the region. Authored the renewable energy section of the utilities' 2009 and 2010 resource planning report.

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- For a company proposing a new merchant transmission project, Ms. Chang was part of a team that developed the valuation model to assist project developer determine the timing and the size of the project. Under the merchant business model, the developer must assume full financial risks for the project. The valuation model used here includes a price forecast tool and a volatility valuation model. Ms. Chang also helped design an open season process and a bidding package for bidders to demonstrate their interested in obtaining transmission rights on the new line.

- Post-deregulation, many former vertically integrated utilities sold off their generation assets and are now in the position of purchasing power on behalf of their customers. For a utility facing significant financial risks through its power purchase activities, evaluated the reasonableness of its purchase methodologies in light of the regulatory uncertainties ever-changing restructuring landscape.

- For a large utility in northeastern U.S. seeking to value its generation assets, conducted a detailed financial and operational performance analysis. Created a comprehensive set of *pro forma* financial statement tool to model different organizational structures and to evaluate the impact of operational efficiency. Valued the utility's power generation plants using simulated free cash flow over the life of each plant. Performed scenario analysis to evaluate keep versus sell alternatives for all or specific plants and assessed options of life extensions and early retirements of particular plants. Generated potential business strategy options for the client to consider and created a tool that the client could use to test out additional strategies.

- For a regulated utility countering an application from a potential competing utility for a certificate of convenience and necessity to construct in its service territory, conducted a cost and benefit analysis of the alternate electricity provider and its electricity prices on the region's industrial and economic development. Examined the potential for regional commercial and industrial growth, particularly in the capital-intensive sectors, which may cause wage rate increases, and evaluated macroeconomic factors such as trade economics.

PUBLICATIONS AND PRESENTED PAPERS

"Plugging In – Can the Grid Handle the Coming Electric Vehicle Load?" Public Utilities Fortnightly, June 2010, (with Dean Murphy, Marc Chupka, Onur Aydin).

"Renewable Integration Model and Analysis" Transmission and Distribution Conference and Exposition, 2010 IEEE Power and Energy Society, (with Kamen Madjarov, Ross Baldick, Antonio Alvarez, and Philip Q Hanser), April 2010.

"2010 Integrated Resource Plan for Connecticut," (with Samuel Newell, Dean Murphy, Marc Chupka, and Mariko Geronimo), January 1, 2010.

"Update on Renewable Energy Market Trends," presented at Seminar on Financing Clean Energy

Projects under the Reinvestment Act of 2009, (organized by Environment Business Council of New England), June 11, 2009.

"Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation," (with Ken Belcher, Johannes P. Pfeifenberger, and Delphine Hou), May 2009.

"Transmission Super Highways: Assessing the Potential Benefits of Extra-High-Voltage Transmission Overlays in the Midwest," (with Peter S. Fox-Penner, Delphine Hou, and Ryan Hledik), March 2009.

"2009 Integrated Resource Plan for Connecticut," (with Onur Aydin, Marc Chupka, Mariko Geronimo, Dean M. Murphy, Samuel A. Newell, and Joseph B. Wharton), January 1, 2009.

"International Renewable Energy Financing," presented at Euromoney's Renewable Energy Finance Forum, New Delhi, India, November 30, 2006.

"Wind Power Grid Integration: How to Evaluate Potential Grid Impact of Proposed Wind Projects", presented at Electric Power 2005 Conference, April 6, 2005.

"LMPs/FTRs Alone Will Not Solve Transmission Problems Blackout Showed" (with Philip Hanser), *Natural Gas and Electricity,* Volume 20, Number 4, November 2003.

"Transmission Management in the Deregulated Electric Industry – A Case Study on Reactive Power" (with Frank C. Graves and Dean M. Murphy), *The Electricity Journal*, Volume 16, Issue 8, October, 2003.

"Transmission Management in the Deregulated Electric Industry – A Case Study on Reactive Power," Ancillary Services Conference, Denver, Colorado, October 9, 2003.

"Regulatory Design for Reactive Power and Voltage Support Services," presented to Comisión de Regulación de Energía y Gas, Bogotá, Colombia, December 2001.

"International Review of Reactive Power Management", presented to Comisión de Regulación de Energía y Gas, Bogotá, Colombia, May 4, 2001.

"Assessment of Energy Demand Growth and the Need for Peaking Plants," Merchant Plant Finance Conference, Atlanta, Georgia, September 14, 2000.

"Competition in Gas Pipeline Markets: International Precedent for Regulatory Coverage Decisions," Report to the National Competition Council of Australia (with Paul Carpenter), June 2000.

"Shortening the NYISO's Installed Capacity Procurement Period: Assessment of Reliability Impacts," NYISO, May 2000.

"Electricity Price Forecasting with Imperfect Market Conditions," Electricity Market Pricing Conference, Denver, Colorado, August 9, 1999.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission (FERC) Docket No. EL09-64-000, Prepared Joint Direct Testimony with Philip Hanser, on Behalf of the City of Vernon, California in its Prepared Petition for Declaratory Order and Request for Waiver of Filing Fee of City of Vernon, California, July 15, 2009

Before Federal Energy Regulatory Commission in Principles for Efficient and Reliable Reactive Power Supply and Consumption, Docket No. AD05-1-000, filed on April 4, 2005.

Before the FERC, Docket No. ER96-496-010, *et al.*, Prepared Joint Affidavit with Philip Hanser on Behalf of Northeast Utilities Service Company and affiliated companies market-based rate authorization, September 27, 2004, Revised December 9, 2004.

Before the FERC, affidavit on behalf of Northeast Utilities in Docket No. ER03-563-030, *Devon Power LLC, etc. al.* Prepared Joint Affidavit with Philip Hanser, filed on March 24, 2004.

August 19, 2010

JÜRGEN WEISS — Principal

Office: Cambridge, MA ♦ Phone: +1.617.864.7900 ♦ Email: Jurgen.Weiss@brattle.com

Dr. Jürgen Weiss heads the firm's climate/carbon practice. He specializes in climate change and carbon market analyses, renewable energy, and electric utility economics. He has significant experience in the development and application of economic and financial models to analyze the impact of proposed rules and regulation on business practices, cash flows, incentives, and the value of power assets and related contracts.

His consulting and expert testimony experience has focused on climate change policy implications for utilities and energy-intensive industries. He advises clients on changes in the value of existing assets, transmission flow patterns and capacity adequacy, integration of renewables, market design and performance analysis, and efficient retail incentives and rate design. He brings institutional knowledge of successful climate practices as well as potential pitfalls from his experience with European efforts to reduce CO_2 emissions.

Dr. Weiss has consulted and written substantially on issues related to carbon pricing and the demand side of electricity markets, including topics such as efficiency, conservation, storage, retail rates, renewable power, and Renewable Portfolio Standards. He has also testified in state and federal court, as well as in state regulatory proceedings.

Prior to joining *The Brattle Group*, Dr. Weiss was a co-founder and managing director of Watermark Economics. In addition, he was previously the managing director of Point Carbon's global advisory practice and a director at LECG. He began his career as an associate with *The Brattle Group*.

Dr. Weiss holds an MBA from Columbia University and a Ph.D. in Business Economics from Harvard University.

AREAS OF EXPERTISE

- *Climate Change and Carbon Economics*
- *Renewable Energy and Energy Efficiency*
- *Electric Power*
- *Market Design and Regulatory Policy*
- *Valuation*

JÜRGEN WEISS

PUBLICATIONS

"What Does Copenhagen Mean for Investments in Low-Carbon Technologies?," Jürgen Weiss, in *The Journal of Environmental Investing*, Beyond Copenhagen, Vol 1, No. 1 (2010), www.thejei.com.

"Using Storage to Capture Renewables: Does Size Matter?," Jürgen Weiss, Judy Chang, and Kathleen Spees; presented at the 15th Annual POWER Conference on Energy Research and Policy, The Energy Institute at Haas, University of California Berkeley, 2010

Comment on "After COP 15, who or what will drive the push towards developing clean energy?," Jürgen Weiss, *Comment: Visions*, January 2, 2010, http://www.commentvisions.com/month/february/2010/visions_from#2

"The Economic Impact of AB 32 on California Small Businesses," Mark Sarro and Jürgen Weiss, prepared for the Union of Concerned Scientists, December 2009.

"Carbon as an Investment Opportunity," Jürgen Weiss and Veronique Bugnion, in *Environmental Alpha*, Angello Calvello (editor), Wiley Finance, November 2009.

"Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects," Jürgen Weiss, Ramteen Sioshansi, Paul Denholm, and Thomas Jenkin, *Energy Economics*, Vol 31 (2009), pp.269-277.

"Waxman-Markey Unintended Consequences of the Auction Reserve Price," Jürgen Weiss and Mark Sarro, June 2009.

"Waxman-Markey Math: What are the numbers and what might they mean?" Jürgen Weiss and Mark Sarro, May 2009.

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"Carbon Cap and Trade versus Tax - Getting beyond the basics," Jürgen Weiss and Mark Sarro, April 2009.

"What to Expect and Not to Expect from Carbon Risk Disclosure," Jürgen Weiss and Mark Sarro, April 2009.

"Whack the MAC: Why we should be skeptical about negative-cost carbon abatement and how to unlock the potential of conservation investments," Jürgen Weiss and Mark Sarro, EUEC Conference and Expo, February 2, 2009.

"Modeling & Forecasting Carbon Prices," Carbon Market Insight — Americas 2008, Jürgen Weiss and Mark Sarro, November 14, 2008.

"Are REC Markets a Wreck Waiting to Happen?" Jürgen Weiss, *Natural Gas & Electricity*, Vol. 23, No. 4, November 2006.

"Integrating Fuel Cells and RPS Markets: Recommendations and Strategies for Advancing Fuel Cells, Distributed Generation and RPS Markets," Jürgen Weiss and Cameron Brooks; A Working Paper by Clean Energy Group, June 2006.

"Economic Challenges to Developing DG under RPS," Jürgen Weiss, EUCI's 2nd Annual Conference on Renewable Portfolio Standards East: Understanding Markets, Development And Technology; Cambridge, MA; May 16-17, 2006.

"A Solution for a Very Old Problem," Jürgen Weiss and Hoff Stauffer, *Electricity Journal* ,Vol. 19 Issue 4, May 2006.

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"Market Power and Power Markets," Jürgen Weiss, *Interfaces*, Volume 32, No. 5, September-October 2002, pp. 37-46.

"New Economy Litigation: Claims to Intellectual Property and Human Capital in a Global Institutional Environment Changing at the Speed of Thought," Jürgen Weiss, Mark Sarro, and Kenneth D. Gartrell, International Society of New Institutional Economics, September 2001.

"Netzzugang in Deutschland im internationalen Vergleich," Jürgen Weiss, Wolfgang Pfaffenberger, Carlos Lapuerta, Hannes Pfeifenberger, Energiewirtschaftliche Tagesfragen, Band 49, Heft 7, 1999, pp (446-451).

"Separate Marketing of Natural Gas by Joint Venture Producers in Australia," Jürgen Weiss and Paul R. Carpenter, prepared for Optima Energy, Australia, submitted to the Upstream Issues Working Group, Australian and New Zealand Minerals and Energy Council, September 26, 1998.

TESTIMONY

Deposition of Dr. Jurgen Weiss in *MC ASSET RECOVERY, LLC, Plaintiff, v. THE SOUTHERN COMPANY, Defendant, CIVIL ACTION No. 1:06-CV-0417-BBM* (February 2008).

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Preliminary Expert Witness Declaration of Jurgen Weiss, Ph.D. in *re: Welding Rod Products Liability Litigation, Case No. 1:03-CV-17000 MDL Docket No. 1535* (February 2005).

Rebuttal Report of Dr. Jurgen Weiss in *Tractebel Energy Marketing, Inc., Plaintiff, against AEP Power Marketing, Inc., American Electric Power Company, Inc., and Ohio Power Company, defendants, 03 CIV.6731(HB)(JCF); and Ohio Power Company and AEP Power Marketing, Inc., Plaintiff, against Tractebel Energy Marketing, Inc. and Tractebel S.A. (now known as Suez-Tractebel S.A.), Defendants. 03 CIV.6770(HB)(JCF)* (February 2005).

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Prefiled Surrebuttal Testimony of Dr. Jurgen Weiss in *Petition and tariff filing of Green Mountain Power Corporation re: proposed rate design changes to take effect January 1, 2005,* in front of the Vermont Public Service Board, Docket No. 6958 (November 2004).

Prefiled Testimony of Dr. Jurgen Weiss in *Petition and tariff filing of Green Mountain Power Corporation re: proposed rate design changes to take effect January 1, 2005,* in front of the Vermont Public Service Board, Docket No. 6958 (August 2004).

Expert Report of Dr. Jurgen Weiss in *Keith Lemon and Lori Lemon, Plaintiffs, vs. Daniel P. McNeil and West Lynn Creamery, Defendants,* in Superior Court of the Commonwealth of Massachusetts, (August 2004).

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JUDY WEI YA CHANG — Principal

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Ms. Judy Chang is an energy economist and policy expert with a background in electrical engineering and over 14 years of experience in advising power companies and project developers with regulatory and financial issues. In the past five years, Ms. Chang has been involved primarily on economic and policy issues around renewable energy planning and deployment. She also has significant experience in transmission-related analyses, including estimating electricity prices in a variety of electricity wholesale markets. In addition, she assists clients on issues of market design, asset valuation, finance, and regulatory policies.

Ms. Chang has submitted expert testimonies to the U.S. Federal Energy Regulatory Commission on capacity markets and reactive power issues and has written numerous testimonies and articles detailing the economic analyses of energy market designs and transmission planning issues, including how the integration of renewable energy might affect electricity markets.

Ms. Chang has also spent several years in India working with global organizations in evaluating and financing renewable energy investments. She received her Bachelor of Science in Electrical Engineering at University of California at Davis and her Master's of Public Policy at Harvard Kennedy School.

AREAS OF EXPERTISE

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- *Electric System Modeling*
- *Regulatory and Market Design Issues*
- *Asset and Contract Valuation*

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Asset and Contract Valuation Related Engagements

- As some electricity wholesale markets become over-saturated with merchant generation facilities, some plant owners have experienced significant financial difficulties and others have been unable to complete previously planned generation projects. For a power plant equipment supplier, Ms. Chang analyzed the eastern regional electricity market in the U.S. and provided litigation support for counsel on estimating the potential value of an unfinished power plant. In addition, provided damage estimations that developer may have incurred resulting from an alleged contract violation.

- For a company proposing a new merchant transmission project, Ms. Chang was part of a team that developed the valuation model to assist project developer determine the timing and the size of the project. Under the merchant business model, the developer must assume full financial risks for the project. The valuation model used here includes a price forecast tool and a volatility valuation model. Ms. Chang also helped design an open season process and a bidding package for bidders to demonstrate their interested in obtaining transmission rights on the new line.

- Post-deregulation, many former vertically integrated utilities sold off their generation assets and are now in the position of purchasing power on behalf of their customers. For a utility facing significant financial risks through its power purchase activities, evaluated the reasonableness of its purchase methodologies in light of the regulatory uncertainties ever-changing restructuring landscape.

- For a large utility in northeastern U.S. seeking to value its generation assets, conducted a detailed financial and operational performance analysis. Created a comprehensive set of *pro forma* financial statement tool to model different organizational structures and to evaluate the impact of operational efficiency. Valued the utility's power generation plants using simulated free cash flow over the life of each plant. Performed scenario analysis to evaluate keep versus sell alternatives for all or specific plants and assessed options of life extensions and early retirements of particular plants. Generated potential business strategy options for the client to consider and created a tool that the client could use to test out additional strategies.

- For a regulated utility countering an application from a potential competing utility for a certificate of convenience and necessity to construct in its service territory, conducted a cost and benefit analysis of the alternate electricity provider and its electricity prices on the region's industrial and economic development. Examined the potential for regional commercial and industrial growth, particularly in the capital-intensive sectors, which may cause wage rate increases, and evaluated macroeconomic factors such as trade economics.

PUBLICATIONS AND PRESENTED PAPERS

"Plugging In – Can the Grid Handle the Coming Electric Vehicle Load?" Public Utilities Fortnightly, June 2010, (with Dean Murphy, Marc Chupka, Onur Aydin).

"Renewable Integration Model and Analysis" Transmission and Distribution Conference and Exposition, 2010 IEEE Power and Energy Society, (with Kamen Madjarov, Ross Baldick, Antonio Alvarez, and Philip Q Hanser), April 2010.

"2010 Integrated Resource Plan for Connecticut," (with Samuel Newell, Dean Murphy, Marc Chupka, and Mariko Geronimo), January 1, 2010.

"Update on Renewable Energy Market Trends," presented at Seminar on Financing Clean Energy

Projects under the Reinvestment Act of 2009, (organized by Environment Business Council of New England), June 11, 2009.

"Assessment of a Maine ISA Structure as a Possible Alternative to ISO-NE Participation," (with Ken Belcher, Johannes P. Pfeifenberger, and Delphine Hou), May 2009.

"Transmission Super Highways: Assessing the Potential Benefits of Extra-High-Voltage Transmission Overlays in the Midwest," (with Peter S. Fox-Penner, Delphine Hou, and Ryan Hledik), March 2009.

"2009 Integrated Resource Plan for Connecticut," (with Onur Aydin, Marc Chupka, Mariko Geronimo, Dean M. Murphy, Samuel A. Newell, and Joseph B. Wharton), January 1, 2009.

"International Renewable Energy Financing," presented at Euromoney's Renewable Energy Finance Forum, New Delhi, India, November 30, 2006.

"Wind Power Grid Integration: How to Evaluate Potential Grid Impact of Proposed Wind Projects", presented at Electric Power 2005 Conference, April 6, 2005.

"LMPs/FTRs Alone Will Not Solve Transmission Problems Blackout Showed" (with Philip Hanser), *Natural Gas and Electricity,* Volume 20, Number 4, November 2003.

"Transmission Management in the Deregulated Electric Industry – A Case Study on Reactive Power" (with Frank C. Graves and Dean M. Murphy), *The Electricity Journal*, Volume 16, Issue 8, October, 2003.

"Transmission Management in the Deregulated Electric Industry – A Case Study on Reactive Power," Ancillary Services Conference, Denver, Colorado, October 9, 2003.

"Regulatory Design for Reactive Power and Voltage Support Services," presented to Comisión de Regulación de Energía y Gas, Bogotá, Colombia, December 2001.

"International Review of Reactive Power Management", presented to Comisión de Regulación de Energía y Gas, Bogotá, Colombia, May 4, 2001.

"Assessment of Energy Demand Growth and the Need for Peaking Plants," Merchant Plant Finance Conference, Atlanta, Georgia, September 14, 2000.

"Competition in Gas Pipeline Markets: International Precedent for Regulatory Coverage Decisions," Report to the National Competition Council of Australia (with Paul Carpenter), June 2000.

"Shortening the NYISO's Installed Capacity Procurement Period: Assessment of Reliability Impacts," NYISO, May 2000.

"Electricity Price Forecasting with Imperfect Market Conditions," Electricity Market Pricing Conference, Denver, Colorado, August 9, 1999.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission (FERC) Docket No. EL09-64-000, Prepared Joint Direct Testimony with Philip Hanser, on Behalf of the City of Vernon, California in its Prepared Petition for Declaratory Order and Request for Waiver of Filing Fee of City of Vernon, California, July 15, 2009

Before Federal Energy Regulatory Commission in Principles for Efficient and Reliable Reactive Power Supply and Consumption, Docket No. AD05-1-000, filed on April 4, 2005.

Before the FERC, Docket No. ER96-496-010, *et al.*, Prepared Joint Affidavit with Philip Hanser on Behalf of Northeast Utilities Service Company and affiliated companies market-based rate authorization, September 27, 2004, Revised December 9, 2004.

Before the FERC, affidavit on behalf of Northeast Utilities in Docket No. ER03-563-030, *Devon Power LLC, etc. al.* Prepared Joint Affidavit with Philip Hanser, filed on March 24, 2004.

August 19, 2010

ESTIMATED RATEPAYER SAVINGS FROM FINANING COST ADJUSTMENT

Project capacity	MW	468	Debt financing	$MM	1,835	Tax Rate	%/year	35%
Installed cost	$/kW	$ 5,600	Debt term	years	15	Price esc.	%/year	3.5%
			Debt ratio	%	70.0%			
			Debt cost, base	%/year	7.5%			
			Debt cost, obtained	%/year	5.0%			
			Ratepayer share	%	75%			

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year			**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Starting balance	$MM		$ 1,835	$ 1,750	$ 1,660	$ 1,567	$ 1,468	$ 1,365	$ 1,256	$ 1,142	$ 1,023	$ 897	$ 765	$ 627	$ 481	$ 329	$ 168
Interest	$MM	5.0%	$ 92	$ 87	$ 83	$ 78	$ 73	$ 68	$ 63	$ 57	$ 51	$ 45	$ 38	$ 31	$ 24	$ 16	$ 8
Payment	$MM		$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)	$ (177)
Ending balance	$MM		$ 1,750	$ 1,660	$ 1,567	$ 1,468	$ 1,365	$ 1,256	$ 1,142	$ 1,023	$ 897	$ 765	$ 627	$ 481	$ 329	$ 168	$ (0)
Average balance	$MM		$ 1,792	$ 1,705	$ 1,613	$ 1,517	$ 1,416	$ 1,311	$ 1,199	$ 1,083	$ 960	$ 831	$ 696	$ 554	$ 405	$ 248	$ 84
Interest rate difference	%	2.5%															
After-tax	%	1.6%															
Ratepayer savings	$MM	$ 187.9	$ 21.84	$ 20.78	$ 19.66	$ 18.49	$ 17.26	$ 15.97	$ 14.62	$ 13.19	$ 11.70	$ 10.13	$ 8.48	$ 6.75	$ 4.94	$ 3.03	$ 1.03
National Grid discount rate		7.0%															
Discount factor			0.967	0.903	0.844	0.789	0.738	0.689	0.644	0.602	0.563	0.526	0.491	0.459	0.429	0.401	0.375
Ratepayer savings NPV	$MM	$ 135.1	$ 21.11	$ 18.77	$ 16.60	$ 14.59	$ 12.73	$ 11.01	$ 9.42	$ 7.94	$ 6.58	$ 5.33	$ 4.17	$ 3.10	$ 2.12	$ 1.21	$ 0.38
Credit Adj. Price	$/MWh		$ 187.00	$ 193.55	$ 200.32	$ 207.33	$ 214.59	$ 222.10	$ 229.87	$ 237.92	$ 246.24	$ 254.86	$ 263.78	$ 273.01	$ 282.57	$ 292.46	$ 302.70
Ratepayer savings	$/MWh		$ 14.36	$ 13.66	$ 12.93	$ 12.16	$ 11.35	$ 10.50	$ 9.61	$ 8.67	$ 7.69	$ 6.66	$ 5.58	$ 4.44	$ 3.24	$ 1.99	$ 0.67
Financing Adj. Price	**$/MWh**		**$ 172.64**	**$ 179.88**	**$ 187.39**	**$ 195.17**	**$ 203.24**	**$ 211.60**	**$ 220.26**	**$ 229.24**	**$ 238.55**	**$ 248.20**	**$ 258.21**	**$ 268.58**	**$ 279.32**	**$ 290.47**	**$ 302.02**
Financing Adj. Price	**$/MWh Levelized**		**$220.98**														

REDACTED

SUMMARY OF OFFSHORE WIND POWER PROJECTS OUTSIDE OF THE U.S.

	Project Name	Country	Initial Year	Project Capacity (MW)		Project Name	Country	Initial Year	Project Capacity (MW)
A. Commissioned									
1	Thornton Bank	Belgium	2009	30.0	22	Lely	Netherlands	1994	2.0
2	Bohai Bay	China	2007	1.5	23	Dronten/Irene Vorrink	Netherlands	1996	16.8
3	Vindeby	Denmark	1991	5.0	24	Egmond aan Zee	Netherlands	2007	108.0
4	Tuno Knob	Denmark	1995	5.0	25	Princess Amalia	Netherlands	2008	120.0
5	Middelgrunden	Denmark	2001	40.0	26	Hywind/Karmoy (Floating Pilot)	Norway	2009	2.3
6	Horns Rev	Denmark	2002	160.0	27	Bockstigen	Sweden	1997	2.8
7	Samsoe	Denmark	2002	23.0	28	Yttre Stengrund	Sweden	2001	10.0
8	Frederikshavn	Denmark	2003	10.6	29	Utgrunden	Sweden	2002	11.4
9	Nysted	Denmark	2004	165.6	30	Lillgrund	Sweden	2008	110.4
10	Ronland	Denmark	2004	17.2	31	Gasslingegrund (Lake Vanern)	Sweden	2009	30.0
11	Horns Rev Expansion	Denmark	2009	209.3	32	Blyth	United Kingdom	2000	4.0
12	Sprogo	Denmark	2009	21.0	33	North Hoyle	United Kingdom	2003	60.0
13	Kemi Ajos Phase I	Finland	2007	15.0	34	Scroby Sands	United Kingdom	2004	60.0
14	Kemi Ajos Phase II	Finland	2008	15.0	35	Kentish Flats	United Kingdom	2005	90.0
15	Emden Nearshore	Germany	2004	4.5	36	Barrow	United Kingdom	2006	90.0
16	Rostock	Germany	2006	2.5	37	Beatrice (Moray Firth)	United Kingdom	2006	10.0
17	Hooksiel (Demonstration)	Germany	2008	5.0	38	Burbo Bank	United Kingdom	2007	90.0
18	Alpha Ventus	Germany	2009	60.0	39	Inner Dowsing	United Kingdom	2008	97.2
19	Arklow Bank	Ireland	2005	25.0	40	Lynn	United Kingdom	2008	97.2
20	Blue H Puglia (Pilot)	Italy	2007	0.1	41	Gunfleet Sands I	United Kingdom	2009	108.0
21	Setana	Japan	2004	1.3	42	Rhyl Flats	United Kingdom	2009	90.0
					43	Robin Rigg	United Kingdom	2009	180.0
Subtotal									**2,206.7**

	Project Name	Country	Initial Year	Project Capacity (MW)
B. Under Construction				
1	Avedore/Hvidovre	Denmark	2010	15.0
2	Rodsand II	Denmark	2010	207.0
3	Baltic I	Germany	2010	48.3
4	Bard Offshore I	Germany	2010	400.0
5	Borkum West II	Germany	2011	400.0
6	Borkum Riffgat	Germany	2012	264.0
7	Greater Gabbard Phase I	United Kingdom	2010	150.0
8	Ormonde	United Kingdom	2011	150.0
9	Walney Island Phase II	United Kingdom	2012	183.6
Subtotal				**1,817.9**

	Project Name	Country	Initial Year	Project Capacity (MW)
C. Financed				
1	Belwind	Belgium	2011	165.0
2	Nordergrunde	Germany	2010	90.0
3	Gunfleet Sands II	United Kingdom	2010	64.8
4	Walney	United Kingdom	2010	151.2
5	Thanet	United Kingdom	2011	300.0
6	London Array	United Kingdom	2012	630.0
7	Sheringham Shoal	United Kingdom	2012	316.8
Subtotal				**1,717.8**

ALL PROJECTS	**5,742.4**

Source: NYSERDA, “New York’s Offshore Wind Energy Development Potential in the Great Lakes, A feasibility study," Final Report 10-04, April 2010.

REDACTED

SUMMARY OF OFFSHORE WIND PROJECT COST OUTSIDE OF THE U.S.

	Project Name	Country	Status*	Initial Year	Project Capacity (MW)	Turbines	Turbine Size (MW)	Water Depth (m)	Offshore Distance (km)	Project Cost ($M)	Project Cost ($M/MW)
1	Belwind	Belgium	C	2011	165.0	55	3.0	20 to 35	46	$ 897	$5.4
2	Sea Bridge	China	B	2010	102.0	34	3.0	8 to 10	8 to 14	$ 345	$3.4
3	Middelgrunden	Denmark	A	2001	40.0	20	2.0	5 to 10	2 to 3	$ 51	$1.3
4	Horns Rev	Denmark	A	2002	160.0	80	2.0	6 to 14	14 to 17	$ 295	$1.8
5	Nysted	Denmark	A	2004	165.6	72	2.3	6 to 10	6 to 10	$ 316	$1.9
6	Horns Rev Expansion	Denmark	A	2009	209.3	91	2.3	9 to 17	30	$ 854	$4.1
7	Alpha Ventus	Germany	A	2009	60.0	12	5.0	30	45	$ 350	$5.8
8	Nordergrunde	Germany	C	2010	90.0	18	5.0	4 to 20	30	$ 440	$4.9
9	Egmond aan Zee	Netherlands	A	2007	108.0	36	3.0	17 to 23	8 to 12	$ 300	$2.8
10	Princess Amalia	Netherlands	A	2008	120.0	60	2.0	19 to 24	> 23	$ 582	$4.9
11	Lillgrund	Sweden	A	2008	110.4	48	2.3	2.5 to 9	10	$ 254	$2.3
12	North Hoyle	United Kingdom	A	2003	60.0	30	2.0	5 to 12	7.5	$ 138	$2.3
13	Scroby Sands	United Kingdom	A	2004	60.0	30	2.0	2 to 10	3	$ 136	$2.3
14	Kentish Flats	United Kingdom	A	2005	90.0	30	3.0	5	8.5	$ 179	$2.0
15	Barrow	United Kingdom	A	2006	90.0	30	3.0	15	7	$ 172	$1.9
16	Burbo Bank	United Kingdom	A	2007	90.0	25	3.6	10	5.2	$ 170	$1.9
17	Inner Dowsing	United Kingdom	A	2008	97.2	27	3.6	10	5.2	$ 289	$3.0
18	Gunfleet Sands I	United Kingdom	A	2009	108.0	30	3.6	2 to 15	7	$ 406	$3.8
19	Rhyl Flats	United Kingdom	A	2009	90.0	25	3.6	8	8	$ 358	$4.0
20	Robin Rigg	United Kingdom	A	2009	180.0	60	3.0	>5	9.5	$ 651	$3.6
21	Gunfleet Sands II	United Kingdom	C	2010	64.8	18	3.6	2 to 15	7	$ 275	$4.2
22	Walney	United Kingdom	C	2010	151.2	42	3.6	20	7	$ 746	$4.9
23	Thanet	United Kingdom	C	2011	300.0	100	3.0	20 to 25	7 to 8.5	$ 1,200	$4.0
24	London Array	United Kingdom	C	2012	630.0	175	3.6	23	>20	$ 3,095	$4.9
25	Sheringham Shoal	United Kingdom	C	2012	316.8	88	3.6	16 to 22	17 to 23	$ 1,500	$4.7

			($M/MW)			
	Status	Number	Minimum	Maximum	Average	Median
	Commissioned	17	$1.3	$5.8	$2.9	$2.3
	Under Construction	1	$3.4	$3.4	$3.4	$3.4
Average Cost	Financed	7	$4.0	$5.4	$4.7	$4.9
($M/MW)	**ALL PROJECTS**	**25**	**$1.3**	**$5.8**	**$3.4**	**$3.6**

*A = Commissioned; B = Under Construction; C = Financed

Source: NYSERDA, “New York’s Offshore Wind Energy Development Potential in the Great Lakes, A feasibility study," Final Report 10-04, April 2010.

REDACTED

SUMMARY OF OFFSHORE WIND PROJECT COST OUTSIDE OF THE U.S., CALIBRATED TO CAPE WIND

	Project Name	Country	Status*	Initial Year	Project Capacity (MW)	Turbines	Turbine Size (MW)	Water Depth (m)	Offshore Distance (km)	Project Cost ($M)	[1] Project Cost ($M/MW)	[2] Distance Scale Factor	[3] Depth Scale Factor	[4] Overall Scale Factor	[5] Adjusted Cost ($M/MW)
1	Belwind	Belgium	C	2011	165.0	55	3.0	20 to 35	46	$ 897	$5.4	1.09	1.11	1.21	$4.6
2	Sea Bridge	China	B	2010	102.0	34	3.0	8 to 10	8 to 14	$ 345	$3.4	1.01	1.00	1.01	$3.4
3	Middelgrunden	Denmark	A	2001	40.0	20	2.0	5 to 10	2 to 3	$ 51	$1.3	1.00	1.00	1.00	$1.3
4	Horns Rev	Denmark	A	2002	160.0	80	2.0	6 to 14	14 to 17	$ 295	$1.8	1.02	1.00	1.02	$1.8
5	Nysted	Denmark	A	2004	165.6	72	2.3	6 to 10	6 to 10	$ 316	$1.9	1.01	1.00	1.01	$1.9
6	Horns Rev Expansion	Denmark	A	2009	209.3	91	2.3	9 to 17	30	$ 854	$4.1	1.05	1.00	1.05	$3.9
7	Alpha Ventus	Germany	A	2009	60.0	12	5.0	30	45	$ 350	$5.8	1.09	1.15	1.25	$4.7
8	Nordergrunde	Germany	C	2010	90.0	18	5.0	4 to 20	30	$ 440	$4.9	1.05	1.00	1.05	$4.7
9	Egmond aan Zee	Netherlands	A	2007	108.0	36	3.0	17 to 23	8 to 12	$ 300	$2.8	1.01	1.03	1.04	$2.7
10	Princess Amalia	Netherlands	A	2008	120.0	60	2.0	19 to 24	> 23	$ 582	$4.9	1.04	1.04	1.09	$4.5
11	Lillgrund	Sweden	A	2008	110.4	48	2.3	2.5 to 9	10	$ 254	$2.3	1.01	1.00	1.01	$2.3
12	North Hoyle	United Kingdom	A	2003	60.0	30	2.0	5 to 12	7.5	$ 138	$2.3	1.01	1.00	1.01	$2.3
13	Scroby Sands	United Kingdom	A	2004	60.0	30	2.0	2 to 10	3	$ 136	$2.3	1.00	1.00	1.00	$2.3
14	Kentish Flats	United Kingdom	A	2005	90.0	30	3.0	5	8.5	$ 179	$2.0	1.01	1.00	1.01	$2.0
15	Barrow	United Kingdom	A	2006	90.0	30	3.0	15	7	$ 172	$1.9	1.00	1.00	1.00	$1.9
16	Burbo Bank	United Kingdom	A	2007	90.0	25	3.6	10	5.2	$ 170	$1.9	1.00	1.00	1.00	$1.9
17	Inner Dowsing	United Kingdom	A	2008	97.2	27	3.6	10	5.2	$ 289	$3.0	1.00	1.00	1.00	$3.0
18	Gunfleet Sands I	United Kingdom	A	2009	108.0	30	3.6	2 to 15	7	$ 406	$3.8	1.00	1.00	1.00	$3.8
19	Rhyl Flats	United Kingdom	A	2009	90.0	25	3.6	8	8	$ 358	$4.0	1.01	1.00	1.01	$4.0
20	Robin Rigg	United Kingdom	A	2009	180.0	60	3.0	>5	9.5	$ 651	$3.6	1.01	1.00	1.01	$3.6
21	Gunfleet Sands II	United Kingdom	C	2010	64.8	18	3.6	2 to 15	7	$ 275	$4.2	1.00	1.00	1.00	$4.3
22	Walney	United Kingdom	C	2010	151.2	42	3.6	20	7	$ 746	$4.9	1.00	1.03	1.04	$4.8
23	Thanet	United Kingdom	C	2011	300.0	100	3.0	20 to 25	7 to 8.5	$ 1,200	$4.0	1.01	1.05	1.06	$3.8
24	London Array	United Kingdom	C	2012	630.0	175	3.6	23	>20	$ 3,095	$4.9	1.03	1.05	1.09	$4.6
25	Sheringham Shoal	United Kingdom	C	2012	316.8	88	3.6	16 to 22	17 to 23	$ 1,500	$4.7	1.03	1.03	1.06	$4.5
	Cape Wind			**2013**	**468.0**	**130**	**3.6**	**3 to 12**	**5 to 15**	**$ 2,621**	**$5.6**	**1.01**	**1.00**	**1.01** (a)	**$5.6**

		($M/MW)			
Status	Number	Minimum	Maximum	Average	Median
Commissioned	17	$1.3	$4.7	$2.8	$2.3
Under Construction	1	$3.4	$3.4	$3.4	$3.4
Financed	7	$3.8	$4.8	$4.5	$4.6
ALL PROJECTS	**25**	**$1.3**	**$4.8**	**$3.3**	**$3.6**

Sources and notes:

*A = Commissioned; B = Under Construction; C = Financed

European projects: NYSERDA, "New York's Offshore Wind Energy Development Potential in the Great Lakes, A feasibility study," Final Report 10-04, April 2010.
Cape Wind: See discussion and citations in attached pre-filed testimony.
Scale factors: European Environmental Agency (EEA) Technical Report, "Europe's onshore and offshore wind energy potential," Technical Report 6-2009, where:

Distance (km)	Factor
0	1.000
0 - 10	1.000
10 - 20	1.022
20 - 30	1.043
30 - 40	1.065
40 - 50	1.086
50 - 100	1.183
100 - 200	1.408
> 200	1.598

Depth (m)	Factor
0	0.000
10 - 20	10 - 20
20 - 30	20 - 30
30 - 40	30 - 40
40 - 50	40 - 50

[1] : NYSERDA
[2], [3] : EEA, interpolated
[4] = [2] x [3]
[5] = [1] x [4(a)] / [4]

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Discounted Cash Flow Projection for Cape Wind[1]

			Construction		Operation																						
Year			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Revenue		Levelized																									
Contract price	$/MWh	$232.74			189	196	202	209	217	224	232	240	249	257	266	276	285	295	306	-	-	-	-	-	-	-	-
Contract revenue	$/kW				614	635	658	681	704	729	755	781	808	837	866	896	928	960	994	-	-	-	-	-	-	-	-
Market revenue	$/kW				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	447	461	473	484	497	510	523	537
Total revenue	$/kW				**614**	**635**	**658**	**681**	**704**	**729**	**755**	**781**	**808**	**837**	**866**	**896**	**928**	**960**	**994**	**447**	**461**	**473**	**484**	**497**	**510**	**523**	**537**
Expenses																											
O&M expense	*$/MWh*				*(50)*	*(52)*	*(54)*	*(55)*	*(57)*	*(59)*	*(61)*	*(64)*	*(66)*	*(68)*	*(71)*	*(73)*	*(76)*	*(78)*	*(81)*	*(84)*	*(87)*	*(90)*	*(93)*	*(96)*	*(99)*	*(103)*	*(107)*
O&M expense	$/kW				(163)	(168)	(174)	(180)	(186)	(193)	(200)	(207)	(214)	(221)	(229)	(237)	(246)	(254)	(263)	(272)	(282)	(292)	(302)	(312)	(323)	(335)	(346)
Depreciation	$/kW				(960)	(1,537)	(922)	(553)	(553)	(277)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total expenses	$/kW				**(1,123)**	**(1,705)**	**(1,096)**	**(733)**	**(740)**	**(470)**	**(200)**	**(207)**	**(214)**	**(221)**	**(229)**	**(237)**	**(246)**	**(254)**	**(263)**	**(272)**	**(282)**	**(292)**	**(302)**	**(312)**	**(323)**	**(335)**	**(346)**
Pre-tax income	$/kW				(509)	(1,069)	(438)	(53)	(35)	260	555	574	594	615	637	659	682	706	731	175	179	181	183	185	186	188	190
Taxes	$/kW				178	374	153	18	12	(91)	(194)	(201)	(208)	(215)	(223)	(231)	(239)	(247)	(256)	(61)	(63)	(63)	(64)	(65)	(65)	(66)	(67)
Tax Credit	$/kW				798	798	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net income	$/kW				**467**	**103**	**(285)**	**(34)**	**(23)**	**169**	**361**	**373**	**386**	**400**	**414**	**428**	**443**	**459**	**475**	**114**	**116**	**118**	**119**	**120**	**121**	**122**	**124**
Depreciation	$/kW				960	1,537	922	553	553	277	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net cash flow	$/kW				**1,428**	**1,639**	**637**	**519**	**530**	**445**	**361**	**373**	**386**	**400**	**414**	**428**	**443**	**459**	**475**	**114**	**116**	**118**	**119**	**120**	**121**	**122**	**124**
PV Factor	$/kW	NPV	0.96	0.88	0.81	0.74	0.68	0.63	0.58	0.53	0.49	0.45	0.41	0.38	0.35	0.32	0.29	0.27	0.25	0.23	0.21	0.19	0.18	0.16	0.15	0.14	0.13
PV of cash flow	$/kW	5,151	-	-	1,156	1,220	436	326	306	236	176	167	159	151	144	137	130	124	118	26	24	23	21	20	18	17	16
Initial cash outlay	$/kW	(5,151)	(2,684)	(2,467)																							

[1] Based on the Cape Wind Estimated Cost Inputs shown in Table 6 of EXHIBIT AG-JWJC-1.

REDACTED